BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Investigation pursuant to Senate Bill 380 to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility located in the County of Los Angeles while still maintaining energy and electric reliability for the region.	Investigation 17-02-002

COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G)

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Pursuant to the Administrative Law Judge's September 14, 2018 Ruling Entering into Record Energy Division's Final Phase 1 Scenarios Framework, Requesting Comment and Setting Procedure to Request Phase 1 Evidentiary Hearings, Southern California Gas Company (SoCalGas) submits the following Comments on Energy Division's September 13, 2018 Scenarios Framework I.17-02-002 (Scenarios Framework). SoCalGas appreciates the work the California Public Utilities Commission's (Commission) Energy Division has done in preparing the Scenarios Framework to assist in determining the importance of Aliso Canyon in maintaining energy reliability and affordability in California and surrounding states. As set forth below, SoCalGas offers comments on the Scenarios Framework proceeding generally, and on the hydraulic modeling, production cost modeling, and economic modeling specifically.

I. BACKGROUND

This proceeding has potential far-reaching impacts on energy reliability both in California and in the surrounding western region of the United States.[1] Reducing or eliminating

[1] Aliso Canyon is an important component of energy reliability in California and the western United States. As SoCalGas has noted before, the Commission's analysis should not be limited to impacts within California. Weather and market events outside of California will impact the price and availability of California's natural gas supply, and the loss of storage in California will impact prices and reliability in

Aliso Canyon will reduce natural gas supply, reduce reliability, and increase natural gas prices. The question this proceeding is trying to answer is: by how much?

SoCalGas operates four storage fields – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey – as an essential part of an integrated transmission system. Aliso Canyon is by far the largest of SoCalGas' four storage fields in terms of inventory, injection capacity, and withdrawal capacity. Prior to the Aliso Canyon natural gas leak, Aliso Canyon's inventory represented over half of the total natural gas storage inventory on the SoCalGas system. As a result, SoCalGas' natural gas transmission and distribution system has developed based on there being an available and strategically located source of natural gas supply at the Aliso Canyon storage facility.

Aliso Canyon plays a key role in SoCalGas' delivery of reliable energy at just and reasonable rates to over 20 million people, thousands of businesses, and electric generators, refineries, universities, and hospitals. Natural gas travels slowly – approximately 20-30 miles per hour – and SoCalGas' natural gas receipt points, located at the fringes of the service territory, are too far from the load centers to fully support customers' changing needs throughout the operating day. This situation is further complicated by the fact that California currently receives approximately 95% of its natural gas supply from out of state sources. Because there is no meaningful in-state production of natural gas, the SoCalGas system is almost wholly dependent on out of state deliveries of gas, which makes local natural gas storage critical to energy reliability.

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neighboring states. For example, the June 2018 Western Interconnection Gas – Electric Interface Study found limitations on Aliso Canyon had heightened region-wide reliability risks to the Western Interconnection (a wide area synchronous grid stretching from Western Canada south to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains). Available at: https://www.wecc.biz/Administrative/WECC%20Gas-Electric%20Study%20Public%20Report.pdf.

Furthermore, from a system planning perspective, it is important to understand the potential limitations of out-of-state supplies and the importance of natural gas storage in providing system resiliency, emergency response, and incident mitigation capabilities. SoCalGas' system is at the terminus of several interstate pipelines delivering gas into California and, as a result, SoCalGas is more likely to be impacted by upstream events. There are countless events that could prevent or limit natural gas from reaching California. For example, climate change related emergencies such as wildfires could restrict the capabilities of the upstream system or freezing temperatures could cause a sharp increase in customer demand east of California. When this happens, California has limited options. Today and in the past, underground storage serves as the system's largest contingency and is the primary safeguard against curtailments and the significant safety and economic impacts that can result from curtailments.

As recognized by the California Council of Science and Technology (CCST),[2] in their Technical Report on the Long-Term Viability of Underground Natural Gas Storage in California (CCST Study):

- "The overarching reason for the utilities' underground gas storage is to meet the winter demand for gas."[3]
- "Gas storage could increasingly be called on to provide gas and electric reliability during emergencies caused by extreme weather and wildfires in and beyond California. Both extreme weather and wildfire conditions are expected to increase with climate change. These emergencies can threaten supply when demand simultaneously increases."[4]

[2] The CCST is a nonpartisan, nonprofit organization that responds to the Governor, the Legislature, and other state entities who request independent and impartial assessments of public policy issues affecting the State of California.
[3] California Council on Science and Technology Technical Report: Long-Term Viability of Underground Natural Gas Storage in California at 511.
[4] California Council on Science and Technology Technical Report: Long-Term Viability of Underground Natural Gas Storage in California at 506.

- "Underground gas storage protects California from outages caused by extreme events, notably extreme cold weather that can drastically reduce out-of-state supplies."[5]
- "Nearly every winter has a month with average daily demand that exceeds, or nearly exceeds, pipeline take-away capacity."[6]

As SoCalGas and the CCST Study highlight, underground natural gas storage is an important part of California's energy infrastructure that supports the reliability of the energy system. As such, in reaching its Phase 2 decision, the Commission must consider the potential reliability and economic impacts of reducing the use of Aliso Canyon – including the extreme potential impacts of an unreliable or un-resilient system, including customer curtailments – and compare those to the impact of continuing to operate Aliso Canyon – a facility that the Commission and Division of Oil and Gas and Geothermal Resources (DOGGR) formally determined is safe to operate following completion of a comprehensive safety review in 2017.[7]

II. INTRODUCTION

The Scenarios Framework proposes a complex modeling effort to quantify and understand the reliability and economic value of Aliso Canyon. To accomplish this, the Scenarios Framework proposes three modeling workstreams: hydraulic modeling, production cost modeling, and economic modeling. The Scenarios Framework proposes a process that is ambitious in scope but lacks clarity, detail, and does not adequately assess the broad range of potential reliability and economic impacts that could occur if the use of Aliso Canyon is reduced.

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[5] California Council on Science and Technology Technical Report: Long-Term Viability of Underground Natural Gas Storage in California at 506.
[6] California Council on Science and Technology Technical Report: Long-Term Viability of Underground Natural Gas Storage in California at 496.
[7] See, e.g., July 19, 2017, SB 380 Findings and Concurrence Regarding the Safety of the Aliso Canyon Gas Storage Facility, available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/OpenLettertoSoCalGasandPublic.pdf.

The Scenarios Framework is designed to develop analysis and conclusions on the value of Aliso Canyon and need for the facility in the near, mid, and long term, but includes assumptions and inputs that are unclear and unsupported. These issues are present across all three models.

- The hydraulic modeling underestimates peak customer demand under the Commission's design standard and overestimates the availability of flowing supply and capabilities of SoCalGas' pipelines and storage infrastructure. This combination results in both underestimating the amount of gas needed to reliably serve SoCalGas' customers and overestimating the amount that will be available to serve those customers. As such, the Scenarios Framework does not provide for an appropriate analysis of natural gas system reliability. Phase 2 should modify these assumptions or, at a minimum, perform sensitivity analysis to understand the impacts if these assumptions are incorrect.
- The production cost modeling provides a framework but lacks clarity and detail on the inputs that are to be developed by the balancing authorities, the rationale for the electric reliability and cost criteria, and the data being relied on by Commission staff. The lack of detail and clarity should be addressed in Phase 2 by providing additional rationale and explanation of the production cost model's inputs, assumptions, and the criteria that will be used to measure the scenarios modeled by Energy Division.
- The economic modeling similarly provides a framework but does not provide adequate explanation and detail of how that framework will be used to assess the economic impacts that could result from reductions to Aliso Canyon. Phase 2

should include broader analysis of potential economic impacts resulting from reductions to the use of Aliso Canyon, further discussion and additional clarity on the economic inputs and assumptions, and further explanation of the significance of the economic analysis and how it will be used to inform the Commission's decision regarding Aliso Canyon.

SoCalGas offers comments on these issues below and plans to more fully address them in Phase 2. The Scoping Ruling states that Phase 1 is only developing a "representative list of scenarios and assumptions" and that parties in Phase 2 may "present analysis of scenarios outside those selected in Phase 1."[8] The Scenarios Framework acknowledges the potential for the inputs and assumptions to change during Phase 2.[9] Because the Scoping Ruling and Scenarios Framework indicate that inputs and assumptions are representative and may change in Phase 2, and because parties are provided an opportunity to present their own analysis and scenarios in Phase 2, SoCalGas has decided not to request evidentiary hearings in Phase 1. SoCalGas reserves the right to further contest all Phase 1 scenarios and assumptions in Phase 2; challenge changes made to the "representative" scenarios and assumptions during Phase 2;[10] and may present its own analyses, models, and scenarios in Phase 2 that more fully addresses the reliability and economic impact of reductions to Aliso Canyon. Finally, SoCalGas has offered two separate rounds of comments on Energy Division's framework. For brevity, SoCalGas is

[8] I.17-02-002, June 20, 2017 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge at 8.
[9] See, e.g., Scenarios Framework at 17 ("CPUC staff will investigate the impact of different types of outages on the zonal capacity. Staff may revise the zonal utilization based on findings.")
[10] To the extent Energy Division modifies their approach and framework in Phase 2, in the interest of transparency, changes should be made in writing and served on the service list, so parties are aware of changes and have an opportunity to comment on changes.

not restating all issues raised in prior rounds of comments here but reserves the right to raise these issues again in Phase 2 and has attached the earlier comments to this filing.[11]

III. DISCUSSION

A. Procedural Comments Regarding the Phase 2 Modeling

1) Energy Division Should to Respond to Discovery and Sponsor their Results as Part of Phase 2

Energy Division's analysis in Phase 2 of this proceeding will provide an initial assessment of the reliability and economic impacts of reducing or eliminating Aliso Canyon. Because Energy Division's Phase 2 modeling results will be a starting point for the Commission's Phase 2 determination of the future need for Aliso Canyon, parties to the proceeding must be able to understand how Energy Division analyzed these issues and arrived at its conclusions, have an opportunity to question the analysis and conclusions, and be able to provide alternative analysis and conclusions.

As such, Energy Division should sponsor one or more witnesses to testify regarding its Phase 2 analysis and respond to data requests. This will promote transparency as to how the study was created and how the conclusions were reached, and better inform interested parties who may be preparing their own alternative studies or testimony. This will also create a more transparent process that will better inform alternative studies – which may present other assumptions, unknowns, and inputs – and make for a more well-informed Commission decision that is based on substantial evidence.

To resolve this proceeding based only on an unsponsored Energy Division study would amount to resolving this proceeding based only on uncorroborated hearsay. This would be an unsustainable finding by the Commission. Previously, in *The Utility Reform Network v. Public*

[11] See Attachments A and B.

Utilities Commission, the California Court of Appeal reversed a Commission decision that was determined to be based only on uncorroborated hearsay evidence.[12] As such, to resolve the question of whether Aliso Canyon can be reduced while maintaining energy reliability at just and reasonable rates, the Commission needs substantial evidence. The Commission should accomplish this by providing for Energy Division discovery and testimony.

2) The Commission Should Not Reach Long Term Decisions Affecting Energy Reliability and Affordability Based on Uncertain Assumptions

The Phase 2 models are intended to demonstrate whether, according to the internal logic of the models, it is *possible* for the system to operate reliably and affordably with reductions to Aliso Canyon. The models will not show whether such reductions are *desirable* or *prudent*. The Commission should take exceptional care in considering future use of Aliso Canyon in this proceeding by favoring conservative assumptions and parameters, while accounting for the uncertainty inherent in forecasts. A decision to close Aliso Canyon would be irreversible without great expense and would place energy reliability and affordability for the western United States at risk. When the Commission is considering what inputs or assumptions to make in the scenarios it should err on the side of caution so that the model and assessments are supported by facts and reasonable assumptions, and do not result in future limitations to Aliso Canyon – limitations that could unnecessarily result in customer curtailments and increased costs.

The model will assess whether it is theoretically possible to reduce Aliso Canyon in the near, mid, and long term. A model's results, however, are only as good as its inputs and assumptions. The Scenarios Framework will require Energy Division to make several assumptions regarding SoCalGas' system's capabilities, the capabilities of neighboring natural

[12] Although hearsay evidence is admissible in Commission proceedings, it "may not be solely relied on to support a finding." *The Utility Reform Network v. Public Utilities Com.*, 223 Cal. App. 4th 945, 961 (2014) (citing *Re Communication TeleSystems Internat.*, 66 Cal.P.U.C.2d 286, 292, fn. 8 (1996)).

gas systems, electric systems, customer demand, and regulatory requirements. These assumptions are integral to the accuracy of the modeling outputs. While we may know with some certainty what inputs to use in the 2020 timeframe, it is significantly less clear as we move to 2025 and 2030. Despite this increasing uncertainty, these assumptions will be used to inform important decisions about energy reliability and affordability for SoCalGas' customers, California, and the western region of the Unites States.

For example, the Scenarios Framework indicates that the hydraulic modeling will assume certain capabilities of the SoCalGas system and percent utilization of SoCalGas' Southern, Northern, and Wheeler Ridge Zones. The Scenarios Framework appears to assume that the current nominal system pipeline capacities and non-Aliso Canyon withdrawal capabilities will persist through 2030. This means, through 2030, pipelines must be maintained at these levels and non-Aliso Canyon storage facilities must maintain the same injection, withdrawal, and inventory capabilities. The Scenarios Framework does not indicate any intent to assess whether it is reasonable to assume that these levels will be maintained, but rather appears to view these levels as starting points, applicable through 2030. These assumed operating capabilities, however, do not reflect how the system operates or is likely to operate.[13]

SoCalGas' system is evolving and changing in response to changing customer demand, changing supply conditions, and new regulatory requirements. The SoCalGas system today will not necessarily be the same in 2030 and beyond. For example, the CCST Study noted the potential for California to meet its environmental goals with the use of renewable natural gas such as methane, hydrogen, and CO2, which could require the use of underground storage for

[13] For example, the Scenarios Framework assumes 400 MMCFD at Otay Mesa, a figure that is very rarely achieved because of the high cost and competition for supply in Mexico – competition that is likely to increase as Mexico's natural gas demand increases.

decades to come.[14] In this scenario, California's demand for renewable natural gas or hydrogen displaces some existing natural gas demand and would require continued use of existing natural gas infrastructure, or changes to the natural gas system to better effectuate the production and delivery of renewable natural gas and hydrogen. It is important that the Commission maintain energy pathways and support innovations that assist California in reliably and affordably accomplishing its environmental goals. As such, the Commission must consider the potential future importance and need for existing infrastructure to promote California's energy options, such as renewable natural gas and hydrogen.

As another example, in recent years there have been numerous enhancements to operating and maintenance regulations for pipelines and storage facilities. For storage facilities, new regulations require storage field shut-ins twice per year and mechanical integrity testing of each well as often as once every two years.[15] Both changes will regularly and significantly reduce the withdrawal and injection capabilities of the storage facilities. For pipelines, SoCalGas continues to implement its Transmission Integrity Management Program (TIMP) and Pipeline Safety Enhancement Plan (PSEP). TIMP requires periodic integrity testing to validate safety and may require pipelines be taken out of service for extended periods of time to enhance safety or validate test accuracy. Pipelines and other infrastructure continue to age and diagnostic equipment technology continue to advance, more accurately identifying maintenance issues in need of attention. As the technology advances, it is anticipated that the technology will increasingly identify anomalies that were not apparent before but now that they are identified,

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[14] California Council on Science and Technology Technical Report: Long-Term Viability of Underground Natural Gas Storage in California at 664 ("Widely varying energy systems might meet the 2050 climate goals. Some of these would involve a form of gas [methane, hydrogen, CO2] infrastructure including underground storage, and some may not require as much UGS as in use today.").

[15] See 14 California Code of Regulations Section 1726.6 (Mechanical Integrity Testing) & 1726.7 (Monitoring Requirements).

require maintenance. That combination means that there will likely be more outages in the future than in the past. In addition, PSEP requires SoCalGas to pressure test or replace pipelines to modernize and enhance system safety. Pressure testing and replacing pipelines can require pipelines be taken out of service for extended periods of time. In addition, as PSEP proceeds, SoCalGas has attempted to identify opportunities to reduce pipeline operating pressures (thereby increasing the margin of safety, but also reducing capacity) in lieu of pressure testing or replacement. In the past, Aliso Canyon afforded sufficient system flexibility and resiliency to manage planned and unplanned outages and look for opportunities to reduce operating pressures to more affordably enhance safety. These factors are not considered by the Scenarios Framework. Instead, the Scenarios Framework relies on current nominal capacities and assumes maintenance of that nominal capacity for over a decade. If the analysis proceeds in this fashion, the analysis of the long-term reliability of the system will be based on a significant increase over today's operating capabilities, no further decreases or changes to those capabilities, and maintaining those capabilities for at least 10+ years. These are not reasonable or prudent assumptions when planning for energy reliability.

In order to provide a margin of safety, the modeling assumptions should be conservative and should err on the side of assuming the continued need for existing infrastructure to avoid disposing of critical assets based on overly optimistic or "best-case" scenarios. At a minimum, Phase 2 should include scenarios where demand does not reduce as projected, where capacities do not return to higher levels, and should include sensitivity or probabilistic analyses for any inputs likely to be determinative in the mid and long-term cases. To do otherwise is not prudent system planning and could risk serious and long-term energy issues for the State

B. Phase 2 Modeling Should be Consistent with Prior Commission Decisions

1) <u>The Scenarios Framework Misstates the Commission's 1-in-35 Design Standard</u>

The Scenarios Framework makes several references to the Commission's 1-in-35 design standard for natural gas service but appears to be inconsistent in how it interprets or plans to use the design standard. First, the Scenarios Framework states:

- Noncore, electric gas load: "For the 1- in-35 standard, electric gas load is fully curtailed to zero. This implies that the electric PCM should not allow any consumption of natural gas for electric generation under this scenario."[16]
- Noncore, non-electric gas load: "For the 1-in-35 standard, full curtailment to zero, while maintaining certain carve outs as specified in Rule 23."[17]

Here, the Scenarios Framework correctly describes the 1-in-35 design standard: all noncore customers are curtailed, unless a customer declares an operating emergency under Tariff Rule 23 and SoCalGas determines it is possible to take steps outside the normal curtailment pattern order.[18] Because the potential for customer operating emergencies are customer and condition specific, a Tariff Rule 23 declaration of an operating emergency should not be assumed for system planning. Therefore, the 1-in-35 design standard should assume full noncore curtailment.

Later in the Scenarios Framework, however, the 1-in-35 design standard is indicated as potentially requiring something less than full curtailment:

- Noncore, electric gas load: "For the extreme peak (1-in-35) day, the PCM will perform an out-of-merit production cost model that reduces gas consumption to the minimum to meet NERC reliability standards."[19]

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[16] Scenarios Framework at 10.
[17] Scenarios Framework at 10.
[18] See SoCalGas Tariff Rule 23.C.3.
[19] Scenarios Framework at 13.

- Noncore, non-electric gas load: For both reliability standards (1-in-10 and 1-in-35), the gas demand for noncore, non-electric customers will be obtained directly from SoCalGas.[20]
- As it relates to the creation of electric generation use profiles, the Scenarios Framework indicates it will look at: "another day that represents the 1-in-35 (97.1th percentile) dispatch profile based on total gas use in that month."[21]

Implicit in the Scenarios Framework's later discussion of noncore demand during a 1-in-35 event is that some noncore demand will be met (e.g., to meet NERC reliability standards). This is not consistent with the definition of this design standard. On a 1-in-35 day, all noncore customers are anticipated to be fully curtailed and the Scenarios Framework should assume full noncore curtailment.

SoCalGas supports designing and maintaining the system capacity beyond the bare minimum Commission design standard and supports Commission efforts to maintain a sufficiently reliable, flexible, and resilient system. As such, the Commission may consider the continued reasonableness of a full noncore curtailment design standard or the re-characterization of some noncore load to core, and model additional scenarios under such assumptions.

Maintaining reliability for noncore customers beyond the 1-in-35 design standard appears consistent with the Commission's efforts to maintain noncore reliability during the ongoing Commission-restrictions on the use of Aliso Canyon. For example, the November 2, 2017 Aliso Canyon Withdrawal Protocol provides: "[w]ithdrawals will be made when, in coordination with the Balancing Authorities, it is determined that withdrawals are necessary to maintain reliability overall, to respond to a risk to electric system reliability, and/or to avoid or to limit curtailments

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[20] Scenarios Framework at 13.
[21] Scenarios Framework at 29.

to core and noncore customers."[22] However, the Scenarios Framework should not create or misinterpret the existing design standard. Rather, the Scenarios Framework should acknowledge that, from a policy perspective, it is appropriate to maintain a system that is capable of reliably functioning beyond the minimum Commission reliability design requirements.

C. The Hydraulic Modeling's Assumptions Should Reflect Current Regulatory Requirements and Actual Operational Constraints and Realities

It is inherently difficult to model future energy needs and future behavior almost twelve years into the future, which is why the assumptions underpinning this effort are particularly important. As set forth below, SoCalGas has several concerns about the assumptions in the Scenarios Framework.

The proposed hydraulic modeling is composed of two assessments: a reliability assessment and a feasibility assessment. The reliability assessment will help determine the storage withdrawal needed (including a minimum Aliso Canyon withdrawal rate) to meet the Commission-approved design standards. As such, the reliability assessment must consider withdrawal rates, inventory levels, available wells, flowing supplies, system outages, and customer demand. The feasibility assessment will determine whether the SoCalGas storage fields can maintain inventory levels throughout the year to achieve the withdrawal rate determined to be necessary by the reliability assessment. As such, the feasibility assessments must consider flowing capacity, storage withdrawal rates, storage inventory, available wells, storage injection rates,[23] system outages, and customer demand. Commission staff's

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[22] Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/11.2Protocol%20PUBLIC%20UTILITIES%20COMMISSION.PDF

[23] As addressed further below, the feasibility assessment must consider storage injection capabilities in a more concerted and focused way. The current proposal does not account for changing injection capabilities as field inventory levels change and will result in a significant overestimation of the gas available in storage and the feasibility of meeting Commission design standards.

assumptions on these factors are an integral part of the Phase 2 effort and must reflect current regulatory requirements and actual operational constraints and realities.

As proposed, the hydraulic modeling has expanded, with a <u>minimum</u> of 44 scenarios identified. To the degree that Commission staff or parties modify scenario parameters or assumptions, it will require running those modifications as separate scenarios and will add additional time. At 1-3 weeks per scenario, this will require 11 – 33 months to complete. To complete more scenarios analyses in a shorter amount of time than what SoCalGas has estimated will require SoCalGas to dedicate additional staff to this Commission-directed effort, which will impact SoCalGas' other business processes, such as system capacity studies, service evaluations for new customers, and safety-related assessments due to the limited number of trained and experienced staff that can perform these analyses.

In SoCalGas' earlier comments, SoCalGas stressed the need for a way to define a "successful" model. The Scenarios Framework states that a hydraulic simulation is considered successful if:

- The pressure at all demand nodes is held above the minimum required pressure at these demand points for the duration of the simulation.
- All facilities must operate within established capacities (i.e. demand must be met).
- The maximum pressure does not exceed the Maximum Allowable Operating Pressure (MAOP) at any point or time.
- "Linepack" is restored, i.e. the amount of gas present in the pipeline at the end of the simulation is the equal to the amount as at the beginning of the simulation

- Storage fields can maintain the required withdrawal (or injection) capacity (mass flow rate).[24]

The Scenarios Framework also includes criteria for the reliability and feasibility assessments:

- The reliability assessment must show that the Commission's reliability standards can be met.[25]
- The feasibility assessment must indicate that the minimum storage levels are achievable throughout the year.[26]

SoCalGas agrees that, *at a minimum*, these conditions must be met for a scenario to be viewed as a success. The Commission should also consider whether the system is sufficiently resilient, flexible, and affordable. For example, Phase 2 should provide additional analysis of emergency situations and potential upstream supply disruptions. In other words, meeting the Scenarios Framework's minimum requirements should not end the analysis; rather, it should be the starting point in determining system reliability, including adequate flexibility and resiliency.

1) <u>Models Should Correctly Reflect the Role and Capabilities of SoCalGas' Underground Storage Facilities in Supporting System Reliability</u>

With regard to the key role Aliso Canyon has played in support of system reliability, the Scenarios Framework states:

> When daily or hourly gas demand is higher than the pipeline flowing capacity, gas is withdrawn from storage at Aliso to serve the demand that exceeds the flowing supplies. This functionality is possible because Aliso is close to the major gas load centers.
>
> When daily gas demand is highly variable, for example when electric generation is re-dispatched in the California Independent System Operator (CAISO) hour-ahead or real time market, rapid increases or decreases in the hourly gas load can cause large pipeline pressure swings. Withdrawals from or injections into Aliso can be used to mitigate these pressure swings and keep the pressure within

[24] Scenarios Framework at 18.
[25] Scenarios Framework at 9.
[26] Scenarios Framework at 20.

> operating bounds. This is a critical requirement for maintaining safety and avoiding excessively low pressures from limiting gas flows.[27]

The Scenarios Framework acknowledges these important roles, but the Scenarios Framework does not acknowledge the role Aliso Canyon's injection capacity plays in supporting the system.

Aliso Canyon's injection capacity allows additional flowing supplies to be scheduled and received on the SoCalGas system by serving as an additional and significant "demand center". As a result, flowing supply can be higher than customer demand because excess flowing supply can be injected into Aliso Canyon. This helps alleviate the need for high operational flow orders and increases system flexibility to help maximize flowing supply on the system. This fact was acknowledged in the most recent Commission 715 Report: "without Aliso, systemwide injection capacity is limited, which makes it difficult to inject gas into all the storage fields."[28] As discussed below, injection capacity and assumptions regarding available injection capacity is extremely significant to system operations and to the correct performance of the proposed feasibility assessment.

In addition, the Scenario Framework appears to oversimplify the use and availability of Playa del Rey (referred to in the Scenarios Framework as PDR). First, for the reliability assessment, the Scenarios Framework indicates "PDR can be considered at maximum storage capacity and can supply the corresponding maximum withdrawal rates on any peak day"[29] and "the storage volume at PDR is small enough that, with appropriate forecasting and gas operations, PDR will be at maximum capacity when needed for a highly stressed day."[30]

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[27] Scenarios Framework at 6.
[28] Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/715Report_Summer2018_Final.pdf.
[29] Scenarios Framework at 13.
[30] Scenarios Framework at 19, Footnote 13.

However, for one day of full withdrawal, it takes approximately five days to refill the facility. Therefore, the Scenarios Framework may be overestimating the capabilities of Playa del Rey, especially with regard to multi-day cold weather events or periods of extended colder temperatures.

Next, for the feasibility assessment, the Scenarios Framework states: "[i]n the nominal monthly day of the Feasibility Assessment, PDR must start and end the day with the same quantity of stored gas, i.e., injections and withdrawals must be balanced on a daily basis for a nominal day."[31] It appears that the Scenarios Framework is indicating that the feasibility assessment will assume that Playa del Rey will always be full because it starts full and by the end of the day injections and withdrawals will be balanced. This is not correct, nor is it how the facility is operated (or capable of being operated). It is not an appropriate assumption to assume that withdrawals and injections will be balanced by the end of the day because different demand conditions and system needs drive withdrawals and injections. To assume Playa del Rey will always start and end the day at the same inventory overestimates the capability and availability of Playa del Rey.

The Scenarios Framework should acknowledge the importance of incorporating injection capacities into the Phase 2 modeling and revise the assumed capabilities of Playa del Rey to better represent the realities of the facility and system operations.

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[31] Scenarios Framework at 21.

2) Phase 2 Modeling Should Use Hourly Gas Load Profiles Based on Forecasted Future Days

The Scenarios Framework proposes deriving hourly gas load profiles for each month under the 1-in-10 and 1-in-35 peak day demand conditions.[32] The proposed approach is problematic for two reasons.

First, monthly peak demand conditions do not exist. The Commission's 1-in-10 year and 1-in-35 year system design criteria for SoCalGas' gas system are annual reliability standards that are designed to only occur once every 10 years and 35 years, respectively. Using the Scenarios Framework's proposed methodology, the proposed peak demand conditions would be expected to occur every year for the 1-in-35 condition and three times every year for the 1-in-10 condition. Such peak conditions reflect reliability standards many times lower than those currently approved by the Commission.

Second, the Scenarios Framework proposes to derive hourly gas load profiles using recent data that may not be representative of future gas demand. Temperatures during recent winters have been mild, greatly reducing demand for gas for home heating. Unless hourly gas demand peaks on cold days are similar to those on temperate days, using data from recent years will dramatically understate the future hourly peaks in gas demand that will confront SoCalGas' system. In fact, in the Scenarios Framework, "Staff acknowledges that recent years have not been as extreme in temperature."[33] As such, SoCalGas suggests Energy Division perform sensitivity analysis in Phase 2 to assess the impacts of more extreme load profiles.

[32] Scenarios Framework at 12.
[33] Scenarios Framework at 12, Footnote 7.

3) <u>Phase 2 Should Include Additional Analysis of the Reliability Assessment's Assumptions Regarding Flowing Gas Supplies</u>

The Scenarios Framework explains that "[u]nder the stressed conditions of the Reliability Assessment, it is anticipated that the flowing supplies at the receipt points will be maximized to minimize the withdrawals from storage, including Aliso."[34] Following this general assumption, the Scenarios Framework indicates that it will assume the following zonal capacities:

- Southern Zone 85% of its capacity during peak and extreme peak days.
- Northern Zone: 85% of its capacity during peak and extreme peak days.
- Wheeler Ridge Zone: 100% of its capacity during peak and extreme peak days.

In the near term,[35] and for the reliability assessment, these assumed zonal capacities appear to be a workable *starting point*. It should be noted, however, for the Wheeler Ridge Zone, supply delivered at Wheeler Ridge competes for local pipeline capacity with Honor Rancho withdrawals, something seemingly acknowledged by the Scenarios Framework: "[u]nder the stressed conditions of the Reliability Assessment, it is reasonable to assume that the combination of Wheeler Ridge receipts and Honor Rancho withdrawals will always be pipeline transportation limited and the available aggregate supply from these sources is determined by this limit."[36]

These assumptions, however, do not take into account the potential for other system outages, outages upstream of the SoCalGas system, or other supply or demand conditions elsewhere that could impact the ability of flowing supplies to reach SoCalGas' service territory. As such, the Commission should consider system resiliency, the need for contingencies, and perform sensitivity analysis to determine how reductions to zonal capacity impacts the analysis.

[34] Scenarios Framework at 15.
[35] See Section III.A.2 above.
[36] Scenarios Framework at 14.

4) The Reliability Assessment's Outage Assumptions Should Include Analysis of Scenarios with Additional Outages and Provide An Explanation of How Assumed Outages are Determined

The Scenarios Framework acknowledges that "[b]oth pipeline and storage outages can significantly impact the ability of the natural gas system to serve load on peak days."[37] Following this acknowledgement, the Scenarios Framework notes that "months with the most severe operating conditions are well known, and planned outages can usually be scheduled to occur outside of these months" and concludes that the modeling include "a single plausible unplanned outage (pipeline or storage) that results in the maximum loss of aggregate gas send-out."[38] In determining these outages, the Scenarios Framework proposes the following general guidelines with regard to determining the applicable plausible unplanned outage:

- The highest impact unplanned outage should be determined using historical data rather than coming up with hypothetical unplanned outages.
- The selected plausible unplanned outage should not have a frequency of less than 10% when evaluating the 1-in-10 reliability standard.
- The selected plausible unplanned outage should not have a frequency of less than 3% when evaluating the 1-in-35 reliability standard.

First, while historical outage data can serve as a starting point for analysis, the Scenarios Framework should not rely only historical outage data to forecast future outages. Changing regulatory requirements, advancements in technology, and efforts to upgrade and enhance the SoCalGas system will likely lead to more outages in the future. Accordingly, the Scenarios Framework should perform sensitivity analysis to determine the impact of not just of a single outage but to also capture the effect of a potential multiple outage scenario.

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[37] Scenarios Framework at 16.
[38] Scenarios Framework at 16.

Second, it is unclear how the guideline's frequencies would be calculated. Outages are unlikely events. As a result, it's not clear what is meant by determining an outage that has a 3% or 10% frequency. This requirement should be elaborated upon or removed. Instead, the Commission should look to both historical outage data and other potential unplanned outages to determine potential impact and importance of storage in supporting the system when such an event occurs, or when multiple events occur.

5) The Feasibility Assessment should use Mass Balance Instead of Hydraulic Modeling

The time and resource requirements of these modeling efforts are significant. The resource and time demands of the feasibility assessment could be better managed if Commission Staff elected to perform a mass balance instead of hydraulic modeling for the feasibility assessment.

Energy Division could perform monthly mass balances for the feasibility assessment, similar to the mass balances that the Energy Division performed in its Summer 2018 Supplemental Report to the 715 Report dated June 18, 2018.[39] A mass balance assumes that the mass that enters a system must either leave the system or accumulate within the system. Through this method, the feasibility analysis can measure the gas that would enter the system and then assume that the gas must either be used by customers or injected into storage. Performing hydraulic modeling on average day scenarios, and then assuming that each day of that month will be identical to the simulated day just so that a month-end system inventory level can be

[39] See Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity, and Well Availability for Reliability, draft Summer 2018 Supplemental Report to the 715 Report dated June 18, 2018 (available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/Draft715Report_Summer2018.pdf

estimated, is inefficient because it provides no more value than a mass balance and requires significantly greater time and resources.

As another example, in SoCalGas' most recent summer technical assessment,[40] SoCalGas used public demand forecast data published in the 2016 CGR workpapers for the summer season, a projection of expected storage inventory levels on April 1, and estimates for injection capacity at each field to perform a mass balance examining the ability to fill storage under both the "best" and "worst" case pipeline capacity scenarios. This mass balance was then used to determine what storage levels SoCalGas forecasted it would be able to maintain heading into the 2018-19 winter season.

In Phase 2, Energy Division should perform a mass balance that derives the month-ending storage inventory levels using California Gas Report monthly demand forecasts, assumed/forecasted injection capabilities at our storage fields (taking into consideration planned and unplanned outages and facility injection capabilities), and assumed/forecasted flowing supplies that considers historical flowing supply highs and lows to develop a sensitivity analysis. The use of this simpler calculation will allow the Commission staff to perform the feasibility assessment in a more efficient and timely manner, which should enable Commission staff to perform additional scenarios to take into consideration different assumptions and inputs.

6) <u>Injection Capacity Should be Incorporated into the Feasibility Assessment</u>

For the feasibility assessment, the Scenarios Framework states "[a]ny available excess gas system capacity is used to support injections into underground storage."[41] The Scenarios Framework, however, does not address the injection capabilities of the facilities. Analysis of the

[40] See Attachment C to SoCalGas Advice Letter No. 5275-A (available at: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/5275-A.pdf).
[41] Scenarios Framework at 21.

system should not assume that injections are limitless or that large amounts of flowing supplies can be received without somewhere for the gas to go. The Commission must consider the injection capabilities of the fields in the feasibility assessment.

As currently proposed, the feasibility assessment appears to assume that significant amounts of natural gas will be delivered to the SoCalGas service territory on all months of the year; unlimited by customer demand or the injection capabilities of the fields. To illustrate in a very simple fashion: if the system receives 3 Bcf of gas supply, but customer demand is only 2 Bcf and injection capacity is 0.5 Bcf, the system is out of balance by 0.5 Bcf. As drafted, however, the Scenarios Framework appears to assume that, regardless of injection capacity, the entire 1 Bcf will be injected into storage. This is incorrect and will result in incorrect conclusions regarding the feasibility of maintaining the required inventory and withdrawal rates throughout the year. The assessment does not appear to include consideration of how increasing levels of inventory or required field shut-ins reduce injection capacity at the storage fields.

Absent an understanding of injection capabilities, the feasibility assessment runs the risks of grossly overestimating the amount of gas that could be injected into storage and could conclude in error that the required storage levels can be achieved and maintained – a result that is not accurate or in line with the capabilities of the storage facilities.

7) The Feasibility Assessment's Flowing Gas Supplies Assumptions Are Not Consistent with Operating and Market Realities

For the feasibility assessment, the Scenarios Framework indicates: "[a]s in the Reliability Assessment, the total transmission zone capacity will be assumed at 85% for the Northern and Southern Zone and 100% for the Wheeler Ridge Zone."[42] However, the zonal capacity rationale

[42] Scenarios Framework at 22.

of the reliability assessment does not apply to the feasibility assessment nor is it consistent with operating and market realities.

First, as explained in the discussion of the reliability assessment, the reliability assessment is assessing the system under stressed conditions: "[u]nder the stressed conditions of the Reliability Assessment, it is anticipated that the flowing supplies at the receipt points will be maximized to minimize the withdrawals from storage, including Aliso."[43] In contrast, "the Feasibility Assessment is carried out under 'typical' or 'nominal' system conditions."[44] Therefore, the feasibility assessment should reflect flowing gas supplies needed to support the "typical" or "nominal" demand condition plus those supplies that could be injected into storage.[45] That level of flowing gas supplies is less (and likely far less) than the prescribed 85% for the Northern and Southern Zone and 100% for the Wheeler Ridge Zone and, from a planning perspective, it is not prudent to assume such high levels of available supply throughout the year. These high levels of assumed flowing supplies throughout the year are unsupported by historical flowing supply data and will result in a significant overestimation of the quantity of flowing supplies received by the SoCalGas system.

Next, it is not prudent to plan for system reliability using average or typical years. This, however, appears to be a key assumption of the feasibility assessment: "[a] key assumption of the analysis framed here is that the stressed conditions imposed in the Reliability Assessment are infrequent or that they are, on average, balanced out by abnormally mild system conditions, and do not significantly impact the total storage volumes over a several-month time frame."[46] The Commission is undertaking this modeling effort to develop models to forecast impact and need

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43 Scenarios Framework at 15.
44 Scenarios Framework at 20.
45 The Scenarios Framework should also clarify what it means by typical or nominal system conditions.
46 Scenarios Framework at 20.

through 2030. Over this period, it is unlikely that each year will be typical or average. As the CCST Study noted:

> Good planning requires forecasting peaks, not just using recent recorded peaks. California's utilities plan to a forecast because they cannot know exactly what weather conditions will occur in any given year. If the utilities plan only to meet recent peaks, they run the risk that more extreme conditions will occur and we will not have adequate capacity to serve demand under those more extreme conditions. Looking only at the recent past ignores this critical statistical information.[47]

Further, as also noted by the CCST Study: "[n]early every winter has a month with average daily demand that exceeds, or nearly exceeds, pipeline take-away capacity."[48] In other words, it is not enough to just look at one extreme event as part of the reliability assessment and then assume the rest of the year is typical or average. Prudent planning requires planning for multiple peaks, multi-day cold weather events, and cold-weather years. From a prudent planning standpoint, the Commission should plan conservatively to protect California and SoCalGas customers from supply shortages. As such, the feasibility analysis should examine other scenarios, such as cold year and/or low hydro year conditions, or at a minimum perform sensitivity analysis to understand how the system operates under "non-typical" years.

Finally, the Scenario Framework's high flowing supply assumptions for the year are inconsistent with operating and market realities. To provide a simple illustration, the Scenarios Framework assumes 3,145 MMCFD of flowing supply will arrive at the zones.[49] This assumption is inconsistent with historical deliveries to the system, higher than typical customer demand, and assumes customers will purchase and transport significant amounts of gas above

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[47] California Council on Science and Technology Technical Report: Long-Term Viability of Underground Natural Gas Storage in California at 498.
[48] California Council on Science and Technology Technical Report: Long-Term Viability of Underground Natural Gas Storage in California at 496.
[49] Based on 85% of the nominal capacity of the Northern and Southern Zones and 100% of the nominal capacity of the Wheeler Ridge zone.

their own demand. For example, this past summer customer demand ranged between 1700 MMCFD and 3,000 MMCFD for the entire system, with most months under 2,600 MMCFD. This means the Scenarios Framework is assuming that under "typical" conditions there will be significant overdelivers of gas – sometimes well above 1,000 MMCFD. This can result in operational flow orders and/or gas being denied access to the system.

By relying on these high levels of flowing natural gas supply, the feasibility assessment is making several unsupported assumptions about the system and customer behavior. First, the feasibility assessment is assuming customers will prioritize purchasing flowing supply to meet demand (and not use withdrawals from storage). Customers are therefore assumed to be maximizing and prioritizing flowing supplies to match (and even exceed) their demand. This means customers are not allowed to use their storage rights and are engaging in daily balancing with a 0% negative imbalance tolerance. Second, the feasibility assessment is assuming customers will purchase excess supply above their demand. However, there is no ongoing requirement or mechanism to regularly require or incentivize such behavior. Third, the feasibility assessment will likely be regularly assuming monthly net injections because flowing supplies will be arriving at such high quantities. This ignores the likelihood that withdrawals will be needed, that some months will end with net withdrawals, and does not account for the potential for demand increases or supply interruptions upstream of the SoCalGas system. The above assumptions are not supported by past or expected customer behavior or system operations. The Commission should not rely on these assumptions in determining flowing supplies for the feasibility assessment, but rather use a more specific process to forecast flowing supplies, customer demand, and injection capacity.

8) <u>The Feasibility Assessment Should Include Analysis of Scenarios with Additional Outages</u>

For the feasibility assessment, the Scenarios Framework indicates: "[i]n contrast to the Reliability Assessment, the Feasibility Assessment must consider both planned and unplanned pipeline and storage outages."[50] And: "we propose that each gas pipeline system model (one model per month of the year) be subject to reductions in flowing supply and reductions in storage operations that are consistent with expectations from the historical record of these outages during that month."[51] To do this, the Scenarios Framework will "assume[] a typical year with typical demand and, consequently, a typical outage situation."[52]

Again, historical outage records should only serve as a starting point for analysis. The Commission should perform some form of sensitivity analysis to determine the impact not just of a single outage but to also capture the effect of a potential multiple outage scenario. This applies to both planned and unplanned outages.

There will be additional planned outages in the future when compared to the past. New regulations require operators to take facilities out of service for maintenance at increasing frequency. For example, DOGGR's new underground storage regulations will require a high and low shut-in test each year, which will result in each storage facility being entirely out of service for approximately one week, twice a year.[53] Further, new well mechanical integrity testing requirements will have wells out of service as frequently as every 24 months for testing.[54] As a result, it should be planned that a percentage of a facilities' wells will be out of service for some period annually to comply with this ongoing testing. Compliance with these and other new

[50] Scenarios Framework at 22.
[51] Scenarios Framework at 22.
[52] Scenarios Framework at 23.
[53] See 14 California Code of Regulations Section 1726.7 (Monitoring Requirements).
[54] See 14 California Code of Regulations Section 1726.6 (Mechanical Integrity Testing).

regulations must be factored into the feasibility analysis to allow for a more accurate assessment that assumes compliance with safety regulations. As such, instead of relying only on historical outage data to develop a "typical" outage, the Commission should develop a forward looking and more comprehensive understanding of planned outages, based on historical data and current operating realities and compliance obligations.

D. Phase 2 Should Provide Additional Explanation and Clarity of the Production Cost Modeling

The proposed production cost modeling consists of a production cost model and power flow model. Using these two models, the Scenarios Framework proposes to evaluate the impacts of reductions to Aliso Canyon on electric reliability and costs. The production cost model provides a framework but lacks clarity and detail on the inputs that are to be developed by the balancing authorities, the rationale for the electric reliability and cost criteria, and the data being relied on by Commission staff. Phase 2 should include additional detail, clarity, and explanation of these areas.

1) Phase 2 Should Further Explain The Unconstrained and Minimum Generation Assumptions

To understand the electric generation impacts of reducing or minimizing Aliso Canyon, the Commission should model scenarios where systems are unconstrained. Unconstrained scenarios can then be used to compare to other scenarios to understand potential reliability and cost impacts of reducing Aliso Canyon.

As such, at a high level, SoCalGas supports the Scenarios Framework's production cost model to the extent it proposes to understand economic dispatch of electric generation for an unconstrained system or, as defined by the Scenarios Framework, dispatch under "conditions where electric generators are able to start up, generate, and ramp according to the technical parameters of the individual power plants, without constraints caused by pipeline or gas supply curtailment."[55]

Although SoCalGas supports efforts to understand electric needs when electric generation is unconstrained, it is not clear how the "constrained" or "minimum local generation" scenario will be modeled and used. The "minimum local generation" scenario represents "conditions where pipeline and gas storage constraints have forced curtailment of electric generation." Under the constrained scenario, "electric generators would be curtailed excepting only the minimum amount of generation deemed necessary by the Power Flow Analysis discussed below."[56]

The constrained scenario appears to force curtailments of Los Angeles basin generation to provide an absolute bare minimum of in-basin generation. However, it is not clear if the Commission views this as an appropriate result from a reliability standpoint and what assumptions the Scenarios Framework is making with regard to minimum generation – for example, additional detail should be provided on what electric import capabilities are being assumed and whether electric import outages are considered by the reliability standard. Because these assumptions and outputs are being used to inform a long-term and potentially permanent Commission decision that could severely restrict the SoCalGas system, specifics and details are important.[57] The potential impacts of a constrained system can be significant, and the

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[55] Scenarios Framework at 25 (emphasis added).
[56] Scenarios Framework at 25.
[57] To illustrate the impacts of system constraints, although being addressed in a separate proceeding, Southern California Edison recently indicated in a Petition for Modification of Commission Decisions 15-06-004 and 16-06-039, as modified by D.16-12-016 that high temperatures, constraints on the SoCalGas system, and application of SoCalGas' Tariff Rule 30 balancing noncompliance charges have allegedly increased end-use customer electricity costs by "more than $200 million above historical average heatwave Energy Resource Recovery Account (ERRA)- related costs." (Available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M221/K841/221841663.PDF.).

Commission should not view meeting a bare minimum requirement, for a constrained system, as sufficient for California. As such, the Commission should provide more detail on the purpose of this "minimum local generation" analysis and how it will be used.

2) Phase 2 Should Involve Further Explanation and Efforts to Maximize Transparency of the CAISO and LADWP Power Flow Modeling

As a first step, to develop inputs to the production cost model, Energy Division plans to incorporate power flow modeling performed by the Los Angeles Department of Water and Power (LADWP) and California Independent System Operator (CAISO)[58] as a basis for determining the minimum local generation that must be online to meet NERC requirements.[59] The power flow model will "determine generation needed for minimum transmission reliability in the LA Basin (Minimum Local Generation) under a scenario of no gas constraints (unconstrained system)."[60] As such, the power flow model assumes no constraints on the gas system and that all generating assets are available, and gas is available in sufficient quantities to natural gas fired generators.[61] Under these assumptions, the power flow model determines a minimum required in-basin generation requirement that must be dispatched to support reliability, even if the dispatch is uneconomic. This minimum generation becomes a requirement that the production cost model must dispatch in the Los Angeles basin for a constrained or unconstrained scenario, but it is not the maximum that can or should be dispatched in basin.

In past analysis of minimum local generation needs, included in prior reliability technical assessments,[62] the balancing authorities have determined low minimum generation levels that

[58] Although they are small in comparison to LADWP and CAISO, the Imperial Irrigation District is not included in either the power flow or production cost model. The Imperial Irrigation District should be accounted for in the Phase 2 analysis.
[59] See Scenarios Framework at 28.
[60] Scenario Framework at 28.
[61] See Scenarios Framework at 25 (definition of "unconstrained system").
[62] See http://cpuc.ca.gov/alisoassessments/.

may be achievable in theory, but appear to SoCalGas to be understated, difficult to accomplish, and not appropriate for the purpose of this proceeding's system planning efforts. The minimum generation numbers should be sufficient for planning purposes and able to be used to assess the reliability of the system – including, among other considerations, extreme weather events and the potential for reduced import capabilities. As such, transparency as to these inputs is important. The power flow modeling of LADWP and CAISO should be made available to parties to review and comment on to make sure that the power flow model is appropriately considering affordability and reliability and includes reasonable assumptions. This should include information on scenarios and assumptions that were modeled but not used or provided to the Commission.

Next, the Scenarios Framework does not include sufficient details on how the power flow modeling will occur. Whether the modeling will be done independently or in coordination – either between LADWP and CAISO or between LADWP, CAISO, and the Commission. Relatedly, the Scenarios Framework should indicate whether the power flow models will or are required to use a common set of database and assumptions. An explanation should be provided for the databases and assumptions used as part of the power flow model.

Finally, for a scenario to be acceptable, it appears that the power flow model must be capable of meeting NERC reliability standards, but specifics are not provided. The Commission should clarify what NERC reliability standards must be achieved.

3) <u>The Production Cost Modeling Process and Criteria Should be Clear and Transparent</u>

The production cost model "seeks to quantify what effects will be produced by the closure or curtailment of Aliso Canyon Gas Storage Field, particularly on the electric system."[63]

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[63] Scenarios Framework at 25.

SoCalGas understands this process to involve performing the production cost model under a constrained and unconstrained assumptions so as (1) "produce hourly gas demand from electric generators" to be used as inputs for the hydraulic modeling;[64] and (2) "produce results quantifying the reliability effects (in terms of 'Loss of Loss Expectation' or LOLE) and cost effects in terms of increase in total production cost resulting from removal of gas supply at Aliso."[65] The Scenarios Framework concludes that the "PCM modeling will be completed to answer the fundamental question, 'Does the closure or curtailment of the Aliso Canyon Gas Storage Field cause any significant reliability effects (change of LOLE by 5%) or affect production costs (change total production cost by 5%)?'"[66]

The Scenarios Framework appears to indicate that closure or reductions of Aliso Canyon that cause the production cost model to show a 5% change LOLE or total production cost is significant and means a scenario will not have met a minimum requirement. The Scenarios Framework offers no explanation for why 5% is an appropriate level or how it was determined. A 5% change over the entire electric market would be significant –as could a 1% to 4% change. While it is important for the Scenarios Framework to indicate some levels whereby it can determine whether a modeled scenario is acceptable, it is equally important that the Scenarios Framework explain how that level was derived and why it is reasonable. The Commission should explain the significance of these 5% figures.

In addition, similar to the power flow model, the Commission should make information regarding the production cost model public, in the interest of transparency. This would include any historical data used, calibration efforts, changes or constraints made to the Transmission

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[64] Scenarios Framework at 25.
[65] Scenarios Framework at 25.
[66] Scenarios Framework at 30-31.

Expansion Planning Policy Committee (TEPPC) Common Case dataset or the Anchor Data Set,[67] and changes made to the CAISO Master file (even if the CAISO Master file remains confidential).

Relatedly, the Scenarios Framework indicates that "[t]he [Unified Inputs and Assumptions for RA and IRP PCM Modeling] will be updated with SB100, signed into law on September 10, 2018."[68] The language of Senate Bill 100 lacks specificity with regard to actual implementation, including the amount of electric procurement from eligible renewable resources, the assumed mix and location of electric generating sources, and assumed electric transmission line import capabilities. These assumptions, whether within or outside of southern California, determine how much electricity can be imported into southern California, which impacts how much local gas-fired generation is required. As such, the Commission should make public the future generating resource assumptions for the entire Western Electricity Coordinating Council (WECC).

4) Phase 2 Should Include Additional Explanation of How Daily Gas Usage Profiles Are Created

To determine daily gas usage profiles for input into the hydraulic model, the Scenarios Framework indicates:

> Staff will create daily operating profiles for power plants in Southern California that represent the 1-in-10 Peak and 1-in-35 Extreme Peak operating conditions. Staff will then run SERVM to model hourly electric generation gas demand without gas constraints, export hourly dispatch and fuel use data, and select from the large dataset of possible dispatch profiles. Staff will select two 24-hour profiles for each month to represent the 1-in-10 (peak) and 1-in-35 (extreme peak) gas use design days will be run. These hourly profiles will be used in the hydraulic model Feasibility Assessment and Reliability Assessment.

[67] Scenarios Framework at 26 (referencing the Commission's Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions, which includes the above datasets as data sources and assumptions).
[68] Scenarios Framework at 26, Footnote 17.

This effort, however, requires additional explanation and clarity.

First, the Scenarios Framework indicates that "[h]ourly gas use derived from electric generator dispatch will be aggregated by month, with hourly shapes selected to represent the 1-in-10 Peak Design day and the 1-in-35 Extreme Peak design day."[69] The Scenarios Framework does not include specifics on how this will be accomplished. In the Integrated Resource Plan, it appears that Commission staff calculates averages and then use a "linear stretching" algorithm for the power load to obtain a profile for the peak day. The Commission should clarify if that same approach will be used here or if a different approach will be deployed.

Second, the Scenarios Framework should provide an exact definition of what is meant by "1-in-10 Peak and 1-in-35 Extreme Peak operating conditions." It is unclear how the Scenarios Framework will apply these natural gas system design standards to electric generation. At a minimum, the Commission should clarify (1) whether the operating condition is assuming low or high temperature (the natural gas system is winter peaking, while electric generation tends to peak in the summer); (2) whether the operating condition is applied to peak gas send out or electric generation load; and (3) what hydro conditions are assumed. Furthermore, to understand the impact of other relevant factors, the Commission should include the development of a correlation matrix addressing relevant factors like temperature, wind output, solar output, and adjacent demand, during peak conditions.

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[69] Scenarios Framework at 25.

E. Phase 2 Should Further Explain The Economic Modeling and Engage In Broader Economic Analysis of the Impacts of Reducing the Use of Aliso Canyon

The economic modeling does not provide adequate explanation and detail of how that framework will be used to assess the economic impacts that could result from reductions to Aliso Canyon. Phase 2 should include broader analysis of potential economic impacts resulting from reductions to the use of Aliso Canyon, further discussion and additional clarity on the economic inputs and assumptions, and further explanation of the significance of the economic analysis and how it will be used to inform the Commission's decision regarding Aliso Canyon.

The Scenarios Framework indicates that the purpose of the economic modeling is to "estimate the impacts of reduction in Aliso gas storage on core and noncore natural gas ratepayers."[70] To accomplish this, the economic models will "use historical and future gas price and gas billing data to analyze, estimate, and predict the relationships of the gas system to rate impacts for core gas customers" and "includes analyzing the causes and impacts of natural gas price volatility, the impact of reduction in natural gas storage capability on core customer ratepayer bills, and the impact of tighter gas supply in the SoCalGas system on energy costs for power generation in the CAISO territory."[71] The economic modeling includes three proposed analyses:

- Volatility Analysis
- The Impact of Natural Gas Storage on Ratepayers' Bills
- The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory

[70] Scenarios Framework at 31.
[71] Scenarios Framework at 31.

The economic modeling analyses proposed in the Scenarios Framework is complex and data-driven. As such, to promote transparency, parties should be provided access to public data and code used as part of the analysis and a detailed description of any data and code used that is claimed to be confidential. Further, the results of the economic modeling will be determined not only by the data used, but also by the models chosen. Therefore, once the data to be used in the economic modeling has been received and examined, it is important that a process be undertaken to evaluate which models should be selected to use in the analysis.

In previous iterations, Commission staff had also proposed to perform "analysis of factors that motivate natural gas storage decisions in the SoCalGas system."[72] Although this proposed analysis would have benefited from additional clarity, if this analysis was designed to attempt to quantify the value of storage, it's inclusion would be potentially relevant and useful. The value of storage is an important value to quantify.

As SoCalGas has indicated in prior comments, the proposed economic modeling fails to adequately capture the economic benefits of Aliso Canyon and fails to account for the various direct and indirect economic impacts that reducing or eliminating Aliso Canyon would cause on California and surrounding states and core and noncore customers. Instead, the economic modeling appears primarily limited to core customer and electric generation impacts. Further, although the Scenarios Framework indicates it will consider "future gas price and gas billing data," it is not clear how the proposed economic modeling will forecast and analyze the future cost impacts of reductions or elimination of Aliso Canyon or the operational and market changes that appear assumed to occur in the hydraulic modeling.

[72] Scenarios Framework at 31.

In addition, SoCalGas continues to support additional analysis of other economic impacts of reducing or eliminating Aliso Canyon. A non-exhaustive list of those potential impacts includes:

- Additional costs to firm up supplies to meet core customers' design day needs in lieu of Aliso Canyon. Without Aliso Canyon, SoCalGas does not have sufficient firm supply sources to meet its obligations to customers under design day conditions. SoCalGas would need to secure alternative firm supplies either in the form of long-haul pipeline capacity or LNG supplies, and invest in additional pipeline infrastructure, all of which results in additional costs.
- Seasonal gas cost differentials. Aliso Canyon's significant assets allows SoCalGas' storage customers more opportunity to purchase lower priced gas supplies which typically occurs during non-peak season to reduce their overall gas costs.
- Direct and indirect impacts on electricity prices associated with the interruption or lack of availability of Aliso Canyon. The model should account for impacts on gas and electricity markets and reliability beyond southern California, such as northern California and the western United States. This is because an interruption or lack of availability of Aliso Canyon can affect gas and electricity pricing to the extent gas and electricity needs are satisfied outside southern California.
- General Economic Impacts. Higher gas and electricity prices will reduce economic activity in southern California because there will be some transfer effects to the extent business activity is reduced or moves away from southern

California. This would result in reduced revenues in the form of taxes to state and municipal governments.

- Average price of gas impacts. The average price of gas is distinct from volatility and downstream impacts on electric generation prices. Withdrawals from Aliso Canyon are an additional source of supply that compete with other sources. Taking Aliso Canyon out of the market will in effect reduce supply competition and increase prices.
- Costs associated with decreased reliability. There are economic costs associated with decreased reliability (e.g., impact of curtailments and brownouts). Such events have direct and indirect economic costs associated with them and should be addressed and quantified in the scenarios and are risks that should be identified in the model.

SoCalGas continues to support this and other analyses that will present the Commission with a more complete understanding of the value of Aliso Canyon and natural gas storage. With that noted, SoCalGas offers the following comments on the economic analysis proposed by the Scenarios Framework.

1) The Volatility Analysis Should be Modified to Quantify the Impacts of Reducing the Use of Aliso Canyon

The Scenarios Framework notes that, "[i]n addition to improving reliability, storage can be used to reduce the economic impact of fluctuations in natural gas prices."[73] As such, to quantify this benefit, the Scenarios Framework indicates that "CPUC staff will perform a volatility analysis on prices of gas purchased at the SoCalGas Citygate hub and compare that result to the volatility of gas prices in other relevant markets. CPUC staff will evaluate

[73] Scenarios Framework at 32.

volatilities of natural gas prices at hubs including SoCalGas Citygate, SoCalGas border, PG&E Citygate, Henry Hub, El Paso San Juan Basin, and El Paso Permian Basin by using data from Natural Gas Intelligence (NGI)."[74] Then "if more variation is observed in the SoCalGas Citygate price compared to other markets, CPUC staff will perform a time series model with explanatory variables to study the relationship between the daily price return of the SoCalGas Citygate natural gas pricing hub and explanatory variables."[75] SoCalGas supports efforts to quantify the benefits of storage in reducing market volatility, but offers the following comments on the Scenarios Framework's proposed approach.

First, as an initial step, the Scenarios Framework indicates that "[i]f more variation is observed in the SoCalGas Citygate compared to other markets after computing the volatility using the standard deviation of the price returns."[76] This appears to be an incomplete sentence and does not indicate what the Scenarios Framework will do if more variation in SoCalGas Citygate prices is observed. Even if more variation is not immediately observed, the volatility analysis should proceed. This analysis should not involve only looking at the historical volatility of California prices (because of the number of other factors that can impact California price volatility) but involve a larger effort to understand the impact of Aliso Canyon on price volatility.

Next, the volatility analysis appears to indicate that it will rely on 2015-2018 variables and data sources. This is 2015-2018 insufficient historical data and results drawn from these data would certainly suffer from recency bias. Recent weather in California has been mild[77] – California has not experienced extended periods of extreme hot or cold temperatures from 2015

[74] Scenarios Framework at 32.
[75] Scenarios Framework at 33.
[76] Scenarios Framework at 33.
[77] As acknowledged in the Scenarios Framework. Scenarios Framework at 12, Footnote 7.

to 2018, which has reduced demand. Furthermore, reliance on 2015-2018 data has numerous other complications. For example, during this time, Aliso Canyon was used differently than it was previously. Aliso Canyon was on maximum withdrawal during the end of 2015 and early 2016, after which it was restricted from injections until the summers of 2017, afterwards limitations on inventory have persisted. Also, since the summer of 2016, Aliso Canyon has had restrictions on withdrawals. These operational constraints have impacted system operations, and available supplies, withdrawals, and injections. As such, the Commission's analysis should include earlier historical data points to capture volatility data when Aliso Canyon was being operated in a more normal manner.

Finally, the Scenarios Framework should indicate how this analysis will be used (will it be used in an attempt to understand the impact on core and noncore customer rates?) and how it will be factored into the determination of the benefits of Aliso Canyon and the future need for the facility.

2) <u>Phase 2 Should Provide Additional Explanation of The Impact of Natural Gas Storage on Ratepayers' Bills Analysis</u>

The next analysis proposed by the Scenarios Framework is intended to "[t]o quantify the effect of storage availability on ratepayers" and involves an "econometrics technique called 'Difference in Differences' (DID)."[78] As explained in the Scenarios Framework, "[i]n the DID model, outcomes are observed for two groups during two time periods. One of the groups (treatment group) is exposed to treatment in the second period but not in the first period. The other group (control group) is not exposed during either period."[79] As it relates to analysis of Aliso Canyon, the Scenarios Framework indicates that "CPUC staff will use monthly bill data

[78] Scenarios Framework at 35.
[79] Scenarios Framework at 35.

for SoCalGas (treatment group) and PG&E (control group) customers by household with similar zip codes representing similar areas (similar in weather, household size, income, etc.) before and after the Aliso Canyon leak required curtailment of the Aliso Canyon storage facility."[80] Then, "[o]utcomes before and after the Aliso Canyon leak will be compared between the study group and the comparison group" and "will allow CPUC staff to estimate the effect of curtailment of the Aliso Canyon natural gas storage facility on the monthly natural gas bills of ratepayers in areas close to each other but differing by their exposure to curtailment of natural gas storage."[81] Again, while it is beneficial to understand rate impacts, the proposed approach will not enable an informed decision regarding the potential rate impact of reducing or closing Aliso Canyon.

First, a DID assessment only works if one group (control group) is not impacted by an event. PG&E and its customers, however, are potentially impacted by constraints on Aliso Canyon. For example, as a result of restrictions on the use of Aliso Canyon, electric generation has been shifted from southern to northern California, which increases gas demand and prices in northern California. As has been stressed before, restrictions on a facility having/with the substantial size of Aliso Canyon will have far-reaching impacts and will make the identification of a control group difficult and uncertain. Furthermore, although the Scenarios Framework attempts to choose a select control group of PG&E customers (based on similar areas), the control group is not appropriately controlled. Choosing certain PG&E zip codes does not eliminate the differences between SoCalGas' and PG&E's systems and differences in costs driven by, for example, varying Commission-approved revenue requirements, and rates. Finally, this DID analysis is too narrow to provide insights on whether the Aliso Canyon injection

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[80] Scenarios Framework at 36.
[81] Scenarios Framework at 36.

moratorium has increased customer bills. Customer gas bills, by design, are relatively stable over time and may not reflect the most recent market or gas system operating conditions.

As an alternative, Commission staff can compare the commodity price paid by core customers. Although this will be simpler, it suffers from many of the same issues mentioned above. For example, the control group's commodity price will still be impacted by the other differences between PG&E and SoCalGas customers and the small sample size. In addition, reviewing the commodity price will not in-it-of-itself enable an analysis of the future impact of eliminating Aliso Canyon because the historical commodity price data will still be based on an available (if needed) Aliso Canyon facility, which could impact the commodity price. If the facility's availability is eliminated, it is unclear how the market will react and how commodity prices will respond. These same limitations apply to the proposed analysis of CARE and non-CARE households.

As another alternative, the Commission could examine future and historical consumer bill impacts, which includes estimating economic impacts on different classes of natural gas customers and aggregating these to derive annual cost of service increase and customer bill impact based on standard rate assumptions. Aliso Canyon's economic impact to gas customers' cost of service could include: incremental upstream and in-state transportation charges to replace Aliso Canyon deliverability for core customers, seasonal spreads/intrinsic storage benefits, volatility impact on gas and electric prices, and OFO/balancing impacts on gas prices.

3) <u>Phase 2 Should Provide Additional Explanation of The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory Analysis</u>

The last analysis proposed by the Scenarios Framework is analysis to determine the impact on CAISO power generation:

> The Aliso Canyon facility provides gas supplies to natural gas-fired power plants that play a central role in meeting regional electrical demand and helps them meet peak electrical demands during the summer months. Constrained gas supply from Aliso Canyon could lead to a decrease in the availability of natural gas in Southern California, which would lead to dispatch of power plants outside of Southern California. The increased dispatch and flow of electricity into Southern California may raise electricity prices either through dispatching less fuel-efficient plants or by creating congestion on the electricity transmission system that creates congestion costs. Arguably, these dynamics could mean higher energy costs in the CAISO markets because of the congestion on the transmission network.[82]

To perform this analysis, "CPUC staff proposes two criteria to assess the impact of tighter gas supply on the power generation in the CAISO's territory: the implied market heat rate and the congestion rent assessment, which are discussed briefly below."[83]

The Scenarios Framework's proposed approaches are complex, and it is not clear how these analyses will be translated into an impact on electricity prices. The implied market heat rate calculations are based on data from 2015 to early 2018, which again suffers from the same issue identified above: the 2015-2018 data is both limited and insufficient because recent weather in California has been mild. Further, it is not clear if the implied market heat rate will also be calculated for future years; if it is, the calculation would be based on a predictive set of natural gas prices, but it is not clear how the Scenarios Framework is determining future PG&E CityGate and SoCalGas CityGate prices in future years. For the congestion rent assessment, SoCalGas is unclear how the prices in future years will be determined or how the results will be used.

The impact on the costs faced by electric consumers is better reflected by future wholesale power market price projections with and without Aliso Canyon. Furthermore, Aliso Canyon, through its impacts on the natural gas market price, the availability of Aliso Canyon

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[82] Scenarios Framework at 39.
[83] Scenarios Framework at 40.

will affect electric wholesale price both in northern California and other WECC regions. In this context, SoCalGas recommends using a model that is capable of projecting electricity prices with and without Aliso Canyon, such as PLEXOS, in order to capture Aliso Canyon's impact to electric consumers.

IV. CONCLUSION

SoCalGas appreciates the opportunity to submit comments on the Scenarios Framework and the Commission's continued efforts to perform its critical role in planning and managing California' energy reliability and resiliency.

Respectfully submitted,

SOUTHERN CALIFORNIA GAS COMPANY

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October 9, 2018

ATTACHMENT A

COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G)

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July 24, 2017

BY E-MAIL
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California Public Utilities Commission
Energy Division
505 Van Ness Avenue
San Francisco, CA 94102

RE: Southern California Gas Company's Response to Proposed Scenarios Framework (Investigation 17-02-002)

Dear Energy Division Staff:

Pursuant to the Administrative Law Judge's Ruling Requesting Informal Feedback on Energy Division's Initial Proposed Phase 1 Scenarios and Noticing Workshop dated June 26, 2017 ("Ruling"), and the Scoping Memo and Ruling of [the] Assigned Commissioner and Administrative Law Judge dated June 20, 2017 ("Scoping Memo"), Southern California Gas Company ("SoCalGas") submits its Informal Comments on Energy Division's Initial Proposed Phase 1 Scenarios Framework ("Initial Proposal"). SoCalGas understands the Initial Proposal is being conducted for developing preliminary scenarios related to the future use of Aliso Canyon pursuant to Public Utilities Code section 714 and I.17-02-002.

SoCalGas further understands that the technical workshop will be conducted in a manner which allows only parties an opportunity to provide meaningful input on the proposed scenarios and model.[1] As set forth in SoCalGas' concurrently-filed motion, to ensure and allow for public participation, SoCalGas recommends that a separate public participation hearing be set to allow for public comment (e.g., conduct the technical workshop between the parties during the day, and hold a public participation hearing in the late afternoon / evening).[2]

SoCalGas' Comments to the Initial Proposal is structured as follows: (1) Introduction and Alternative Framework; (2) General Comments to the Models in the Initial Proposal; (3) Specific Comments; and (4) Responses to Questions Posed in the Initial Proposal.

[1] Initial Proposal, Attachment A, at p. 1.
[2] SoCalGas Motion for Additional Workshop, I.17-02-002, filed July 24, 2017.

I. Introduction and Alternative Framework

Energy Division's proposed scenarios framework is not a technical analysis of Aliso Canyon's importance to the natural gas system for achieving energy reliability, but is constructed to validate that the Aliso Canyon storage facility is not needed by making assumptions that the facility is not needed and then crafting the model runs around that assumption.[3] This approach could place California at risk by failing to ensure a reliable supply of energy for California's residents and businesses, and is inconsistent with prior Commission decisions and SB 380. Energy Division needs to create a system that would provide for long term energy reliability and then focus on the most efficient and economical way to run the system. As such, Energy Division should predetermine a set of goals or requirements that would indicate when a model has succeeded. Then, using those criteria, Energy Division should determine whether those criteria can be met under specific circumstances, including planning for contingencies on the system.

Energy Division's analysis, as currently proposed, is biased toward a result that removes Aliso Canyon. It begins with the assumption that Aliso Canyon is unnecessary and then works to validate that assumption using incorrect or overly optimistic assumptions. To do this, Energy Division's framework removes or severely limits Aliso Canyon's contributions and assumes other aspects of the system are running at or near their highest capabilities. This is not an appropriate approach to designing a reliable energy system or maintaining energy reliability in Southern California. Nor is it consistent with creating an energy system that is capable of responding to changes in the marketplace, or technology. Taking this approach could have real, significant, and long term effects not only on the SoCalGas system, but on California and the western United States.

The energy crisis of the early 2000s revealed how a shortage of natural gas and electricity can be devastating to the people, businesses and the economy of the State of California. As the Commission stated in its efforts to prevent another crisis: "Even a shortage in just a couple of months could cause billions of dollars of additional costs, which would not be incurred if there were a balance in the supply and demand. Moreover, the direct connection between natural gas supply and prices and the price of electricity was clearly established during the energy crisis."[4] In determining whether reliable service can continue to be provided without Aliso Canyon, the Commission should fully evaluate these risks. California deserves a flexible energy system, one that is capable of withstanding supply shortages, outages and real-time system changes such as those caused by the increase of renewable electric generation.

The Commission has already mandated certain natural gas system reliability and planning requirements, and opined on the importance of a sufficiently resilient and flexible system. Thus,

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[3] For example, the first sentence of the "Aliso Inventory Level" section on page 3 of the framework indicates that the first inventory level the Commission plans to test is "zero (i.e. closure of Aliso)". The section goes on to indicate that if "…the model determines that Aliso can be closed with no significant impacts..."

[4] Rulemaking 04-01-025, at 4-5.

prior Commission decisions and orders provide guidance on what Energy Division's goals should be:

- Comply with Commission core and noncore design mandates;
- Provide sufficient resiliency; and
- Provide sufficient system flexibility.

Each of the above goals – and the applicable Commission decisions – are discussed in detail below.

<u>Core and Noncore Design Mandates</u>

The Southern California natural gas system operates as a whole, integrated system. Altering or removing one asset impacts SoCalGas' ability to comply with mandated design standards, which will inherently impact the entire system. Such actions cannot be discounted when planning for future energy reliability.

The Commission has previously established planning criteria and reliability standards for SoCalGas.[5] Specifically, the Commission ordered: "The reliability standard of 1-in-35 for core customers, 1-in-10 for noncore customers, and 1-in-35 for core local transmission customers is adopted for Southern California Gas Company (SoCalGas)."[6]

This standard was more recently affirmed and clarified. The Commission again stated a specific design criteria for gas transmission systems: "the systems must be designed to provide service to core customers during a 1-in-35 year cold day event (one curtailment event in 35 years) and service to noncore customers during a 1-in-10 year cold day event (one curtailment event in 10 years)."[7] This standard was then clarified for the backbone transmission system's receipt capacity, using annual average demand forecasts: "It is reasonable to require that each of the utilities plan its backbone system to meet one-in-ten year cold and dry conditions."[8]

Additionally, on March 16, 2017, Timothy Sullivan (Executive Director of the Commission), sent SoCalGas a response to a SoCalGas Storage Safety Enhancement Plan proposal in which the following was stated in pertinent part:

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[5] D.02-11-073, at 46 (Finding of Fact 16).
[6] D.02-11-073, at 49 (Ordering Paragraph 10).
[7] D.06-09-039, at 49-50. The Commission subsequently eliminated the "firm" and "interruptible" designations for noncore service in D.16-07-008, and the design standard now utilizes forecast noncore demand.
[8] D.06-09-039, at 171 (Finding of Fact 6). The Commission further stated in that decision: "We will also make explicit the requirement that the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems." (D.06-09-039, at 27). "It is reasonable to require that each of the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems." (D.06-09-039, at 171 (Finding of Fact 7)).

> [T]he [safety] plan, as presented, will limit the withdrawal capacity of SoCalGas storage facilities to a level that is demonstrably insufficient to meet the expected energy needs of SoCalGas customers this summer, and fails to minimize energy reliability risks and, in turn, the safety-related risks associated with curtailment of electricity supply.[9]

Executive Director Sullivan also required SoCalGas to achieve certain storage withdrawal rates to maintain electric (non-core) reliability for the summer:

> To minimize the risk of energy vulnerabilities this summer and provide for sufficient winter inventory levels, SoCalGas should maintain a system wide storage withdrawal capacity level of 2.065 Bcf per day beginning June 1, 2017, and throughout the balance of the safety enhancement project. That amount should be increased as quickly as possible to 2.420 Bcf per day using improvements to withdrawal capacity at each of the fields, including the management of inventory levels and increases to wells in service at all fields.[10]

SoCalGas has understood these new Commission mandates as imposing new and more demanding operating standards on our system. In the past, SoCalGas has been able to curtail noncore customers to maintain reliability and its current tariff reflect that ability. Based on the March 16, 2017 Letter, SoCalGas understood that the Commission expects, even in extreme conditions, SoCalGas to maintain supply to noncore customers.

This understanding is supported in this proceeding by Energy Division proposing a design standard of 1-in-35 for core customers, and 1-in-10 for noncore customers. In other words, Energy Division is assessing whether service can be maintained to core and noncore customers in extreme weather conditions. If SoCalGas' understanding is incorrect, it would be helpful to the parties for Energy Division to clarify the proposed planning standard that it plans to use for its modeling.

In determining the success of a proposed scenario, Energy Division should determine that the scenario provides a system design that meets applicable design and operational standards.

System Resiliency

System resiliency is the ability of the system to withstand planned and unplanned outages of other assets, respond to supply constraints, and sudden and unexpected increases in demand. The Commission has directed utilities to plan their transmission system to provide reliable

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[9] March 16, 2017 Letter from Sullivan to Schwecke (at page 1), available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/CPUCLettertoSoCalGasreStorageSafetyEnhancementPlan.pdf

[10] *Id.* at p. 2 (emphasis added).

service, including during emergencies such as "failure of a major component of the delivery or storage system, an artificially induced constraint on the flow of gas, a sudden or persistent loss of supply, an unpredicted and unplanned-for rapid increase in demand, or an excessive increase in the market price for gas."[11] These types of contingencies have not been built into the scenarios proposed by Energy Division. Fifteen percent is unreasonable to account for both a reduction in supplies and a planned or unplanned outage of a facility. Failing to include these contingencies is inconsistent with previous Commission direction and requirements.[12]

In addition, there are federal and state regulations with which SoCalGas must comply, as well as necessary maintenance and repairs that must be made to the system in order to continue operating it safely and reliably. It is necessary for the system to be able to continue to operate reliably and safely when assets are temporarily removed from the system to perform this work. As one example, Aliso Canyon continues to provide necessary resiliency and flexibility to allow SoCalGas to take major transmission lines out of service in order to perform federal and state-mandated integrity assessments and repairs.[13]

In determining the success of a proposed scenario, Energy Division should determine that the scenario results in a system that is sufficiently resilient to withstand the "failure of a major component of the delivery or storage system, an artificially induced constraint on the flow of gas, a sudden or persistent loss of supply, an unpredicted and unplanned-for rapid increase in demand, or an excessive increase in the market price for gas" and allow pipes and wells to be temporarily taken out of service for required maintenance work. Energy Division should determine this by running scenarios where specific assets are taken out of service to determine if the system can continue to provide reliable service.

<u>System Flexibility</u>

Flexibility refers to the ability to serve fluctuating loads and supplies all the while managing issues in real-time across SoCalGas' system. As the Commission is aware, it is

[11] D.06-09-039, at 170 (Finding of Fact 1).
[12] D.06-09-039, at 171 (Finding of Fact 3) ("It is not enough to know that the combined available pipeline capacity and storage withdrawal rights exceed peak demand by a certain amount. It is necessary to know that sufficient gas will be stored and that withdrawn gas can be delivered where it is needed when the system is most severely stressed"); D.06-09-039, at 173 (Finding of Fact 22) ("Storage serves purposes far beyond price hedging, and provides certainty that cannot be matched by a reliance on flowing supply"); D.06-09-039, at 173 (Finding of Fact 23) ("Neither SoCalGas nor its unbundled storage customers could rely exclusively on flowing supply in lieu of storage.").
[13] For example, work resulting from the Pipeline Safety Enhancement Plan [see California Public Utilities Code Section 958] and the Transmission Integrity Management Plan. [see 49 C.F.R. 192 – Subpart O; see also, D. 16-12-009]. As another, pending, example, the Department of Conservation's Division of Oil, Gas, and Geothermal Resources ("DOGGR") is proposing to adopt new regulations tailored specifically to underground gas storage facilities and gas storage wells. See DOGGR Proposed Regulation 1726.6 – Mechanical Integrity Test). These new regulations will include more frequent mechanical integrity testing of wells. Testing the wells will necessitate taking wells out of service, which will reduce a facility's withdrawal rate. Further, regulations on integrity requirements may require abandonment of wells over a certain period as short as two years.

critical to the management of a utility that it be able to handle and respond to differing loads at unexpected junctures. Operational flexibility promotes reliability and provides economic benefits by diversifying sources of supply and enabling the utility and customers to respond to market conditions. In assessing need for new projects, the Commission has considered operational flexibility among the benefits provided by gas storage generally.[14] The Commission has also recognized that flexibility is necessary to optimize use of the state's natural gas infrastructure.[15]

In contrast to demand, flowing natural gas supplies delivered to the system at SoCalGas' receipt points occur on a relatively steady basis. SoCalGas depends upon its storage fields to meet the intraday differences between supply and demand. Flowing supply coming into the system comes in too slowly to perform this function, because gas travels approximately 25 miles per hour, and natural gas from flowing supplies take too long to get to where they are needed. More than anything else, it is the flexibility that the storage fields provide to the system that enable SoCalGas to maintain uninterrupted service to our customers.

Over the past several years, it is this system flexibility that has allowed SoCalGas to respond to the dramatic rise in renewable generation. While this change has occurred during this past several years, it was unanticipated that it would happen so quickly. This change has created a focus on reliability during peak hours that have shifted. The Commission must consider the peak hours and not the peak days when determining how much SoCalGas' system needs to rely on the Aliso Canyon Storage Facility for both the short term and the long term. As such, there must be a consideration of hourly load, in addition to daily load, built into the model.

This change has created a focus on reliability during peak hours that have shifted. The Commission must consider the peak hours and not the peak days when determining how much SoCalGas' system needs to rely on the Aliso Canyon Storage Facility for both the short term and the long term. As such, there must be a consideration of hourly load, in addition to daily load, built into the model.

In assessing operational and economic impacts of reduced usage of Aliso Canyon, the Commission should be careful to properly consider and account for loss of flexibility, the impacts of which will be most significant during unplanned contingencies. The Commission should also have a clear understanding of all costs and impacts needs to be evaluated during the proceedings.

II. General Comments to Initial Proposal

Although, consistent with prior Commission decisions and orders, Energy Division should incorporate the framework described above into its modelling effort, SoCalGas submits the following general comments to the current Initial Proposal:

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[14] D.92-11-016; s*ee also* D.12-07-021.
[15] D.92-11-016, at 1.

- Comments Applicable to All Studies in the Initial Proposal
  - The near term, medium term, and long term modeling start and end dates should not be a calendar year but instead be April through March (e.g. April 2018 through March 2019) to properly capture uninterrupted core storage injection and withdrawal cycles.
  - Two consecutive core injection and withdrawal cycles should be modeled simultaneously (i.e. April 2018 through March 2020) to evaluate the core's ability to refill storage after an abnormally cold, high demand winter.
  - In addition to modeling the proposed inventory levels, SoCalGas recommends including a scenario where Aliso Canyon is opened to the inventory level (and corresponding withdrawal rate) consistent with its maximum allowable operating pressure for each of the years modeled.
- Hydraulic Modeling General Comments
  - Hydraulic modeling is a useful tool to assess the capacity of a pipeline network such as SoCalGas', and is a much more appropriate tool for this type of evaluation than a simplistic mass-balance calculation such as those routinely performed by the CEC. However, it is still only a tool to calculate gas flow and pressure losses, and modeling a complex network such as SoCalGas' requires an intimate knowledge of the design and construct of the system in order to interpret and evaluate the simulation results, as well as recognizing and acknowledging the likely boundary conditions and parameters that would alter the results of the hydraulics. The "answer" to the hydraulic analysis will not appear as a single number or parameter, such as would be obtained by pressing the "equals" key on a handheld calculator. The Commission should clarify what metrics will be used to deem a gas hydraulic simulation successful.
  - Instead of only determining the bare minimum required to meet withdrawal requirements, the determination of acceptable Aliso Canyon storage inventory should capture inventory reductions from all the storage fields at the onset of a peak demand event through the end of the event.
  - Assumptions for each non-Aliso Canyon field should be made on withdrawal performance declining as inventory decreases, pressure decreases and the overall withdrawal capacity decreases.
  - Current and ongoing system integrity maintenance (e.g. ongoing restrictions at Ehrenberg and outage of Line 3000) should be considered in receipt point capacity assumptions. It also should include multi-day scenarios, not just a single day.
  - The assumed available receipt capacity should reflect reduced in-state production (i.e. not the posted in-state capacity).
  - The Commission should clarify if the Winter Peak Day Demand forecast will utilize the electric generation forecast (17 plants served by Aliso and remaining plants served by SoCalGas/SDG&E) in the 2016 California Gas Report. (Initial Proposal, pp. 4-5, fn. 5)

  - The Commission should clarify whether the 85% gas receipt point utilization factor (of what number) is an overall cumulative utilization factor or if individual, receipt point-specific utilization factors will be used. (Initial Proposal, p. 5) The model needs to cover planned and unplanned outages.
  - The Commission should clarify if the 8% under delivery factor (see page 5 of the Initial Proposal) includes days when markets outside California experienced high send-out days, thus limiting the supply to California.
  - The Commission should clarify whether previous historical market conditions/events that have impacted gas/electric reliability should be considered for medium/long-term scenarios. Historical data should be included to account for period disruptions to the system.
  - The model should include sensitivity analyses to evaluate the impact of potential gas outage events (e.g., interstate, pipeline, regulator, compressor, storage) for, *inter alia*, system reliability purposes.
  - In addition to taking into account weather-related disruptions, the model should account for disruptions that are not weather-related. For example, Sandia National Laboratories prepared a report in June 2013 as to potential disruptions arising from a major earthquake (e.g., if gas supply line is severed).[16]
- Production Cost Modeling General Comments
  - The model should capture future regional coal plant retirements reducing the capability for power generation gas-to-coal switching, which can affect demand for gas-fired generation.
  - Where applicable, the model should include "once through cooling" regulations for California power plants, to ensure when they model future years for power generation costs, they are retiring the plants listed on the once through cooling schedule.
  - In addition to loss of load events ("LOLE"), electric reliability should be modeled under loss of a major gas supply resource such as a pipeline or storage field (similar to n-1) or an electric transmission loss or power plant loss, so that there is a similar reliability requirement for gas as there is for power.
  - The model should consider peak day conditions that have the potential/likelihood to reduce gas supply with subsequent reductions to power imports to California, such as occurred during the December 2013 freeze-off event.
  - The Commission should clarify if the production cost analysis will examine all electric generating units on the SoCalGas system in California. If the answer is "no," then the Commission should clarify the assumptions to be used for other remaining units served by SoCalGas besides the 17 identified in the Initial Proposal (see page 6 of the Initial Proposal).

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[16] *Natural Gas Resiliency to a "ShakeOut Scenario" Earthquake,* by Sandia National Laboratories (the "Sandia Report"), available at http://prod.sandia.gov/techlib/access-control.cgi/2013/134938.pdf

  - The Commission should clarify the methodology to calculate LOLE, and define the load areas to be used in that calculation. In addition, the Commission should clarify how electric imports will be incorporated in the LOLE analysis. For instance, electric import levels should not remain static in each simulation/level of Aliso Canyon withdrawal, as less gas will be available for local power generation as the storage inventory and withdrawal rate decreases.
  - The Commission should clarify how economic metrics will be accounted for when estimating the LOLE and the gas burn level that will be fed to the hydraulic model. It should first be based on a current dispatch model based on efficiency and economics, not forced to a "no Aliso Canyon" model.
  - In addition to load and renewable output, the Commission should clarify which other variables will be simulated in a probabilistic approach. For example, the Commission should clarify if the "unit performance condition" will simply be a discrete change in response to Aliso Canyon withdrawal levels.
  - The Commission should clarify what is meant by "reliability costs" and what is intended by "other reliability metrics." (Initial Proposal, p. 7.)
  - The Commission should clarify the methodology used to simulate multiple points of load and renewable energy output forecast error. Further, the Commission should clarify how the magnitude in forecast error is derived.
  - If the Commission analysis uses SERVM to "simulate arbitrary operating scenarios with the 17 plants that receive gas from Aliso," the Commission should clarify the approach it will use for the other generation plants served by SoCalGas/SDG&E. If Aliso Canyon is not available, these plants will have to depend on flowing supplies that could also impact flowing supplies to other gas fired generation plants on the system. The approach should be clarified as to how this impact will be considered for the other power plants served by SoCalGas/SDG&E.
  - Estimating gas price impacts should be used for the model as opposed to the static gas prices used in the current model in the Initial Proposal.
- Economic Modeling General Comments
  - The model in the Initial Proposal does not appear to account for direct and indirect impacts on electricity prices associated with the interruption or lack of availability of Aliso Canyon. The model appears only focused on Southern California. Electricity demand outside of Southern California (e.g., Western United States) impacts both gas and electricity availability. If there are power plant disruptions/maintenances outside of California, such events impact gas and electricity availability. The model should account for impacts on gas and electricity beyond southern California, such as northern California and the western United States, because any interruption or lack of availability of Aliso Canyon will affect gas and electricity pricing to the extent such needs for gas and electricity need to be satisfied by going beyond southern California.

- Economic impacts are not limited to gas and electricity. Higher gas and electricity prices will reduce economic activity in Southern California because there will be some transfer effects to the extent work flows away from southern California, including reduced revenues in the form of taxes to state and municipal government. For instance, if natural gas prices go up, paying for that increased commodity price takes otherwise disposable income money out of California, and, obviously, reduces economic activity in California. This will impact consumers and state and local treasuries and is a risk that should be identified in the model.
- To the extent there is a reduction in reliability, there is nothing identified in the Initial Proposal that lays out economic cost associated with decreased reliability (e.g., impact of curtailments and brownouts). Such events have direct and indirect costs associated with them and should be addressed in the scenarios and is a risk that should be identified in the model.
- The model should look at the market structure as part of the proceeding and the current market rules. The Commission should clarify if it is assuming the current temporary changes such as daily balancing will continue. The Commission should also consider asking the parties to provide suggestions to improve reliability and resiliency through market changes.
- The model should consider the impact of Aliso Canyon on natural gas price reductions that translate into electric market price impacts.
- The Commission should provide additional information on how consumer benefits will be determined from economic modeling.

III. Specific Comments to Certain Assumptions in the Initial Proposal

In addition, notwithstanding the general comments addressed above, SoCalGas has the following comments to the Initial Proposal and the questions set forth in the Initial Proposal.

1) Initial Proposal, Page 3: "If the hydraulic model determines that Aliso can be closed with no significant impacts to gas and electric reliability in either summer or winter, then no further modeling would be necessary for that year. If the model determines that Aliso cannot be closed without causing unacceptable reliability impacts, then the system would be modeled including Aliso inventory at the level determined by the 715 report . . ."

   SoCalGas Proposed Revision: "If the hydraulic model determines that the level of demand selected for evaluation cannot be served, then further modeling would be necessary for that year, including Aliso inventory and capacities at various levels. . ."

   Comments: If the parties spend time and resources to develop the gas demand scenario/forecast, then the parties should not then conclude if the consequence of not meeting that demand condition would be "insignificant" or not. The determination should be whether the design condition/standard is met. Moreover, because the

Commission holds SoCalGas to the 1-in-10 year cold day design standard for noncore service, and has stated that SoCalGas should maintain service to noncore customers (e.g., not curtail electric generation), the Commission should include this new requirement in its consideration of whether the results were "insignificant."[17]

2) Initial Proposal at Page 4: "The Winter 2016-17 Assessment used the 1-in-10 CPUC cold winter day design standard, and the Summer 2017 Assessment used the 1-in-10 peak summer electric load as determined by the Western Electricity Coordinating Council (WECC) Operational Study Subcommittee. Several iterations of the model were run testing reliability at various gas receipt point utilization levels."

   Comment: This entire section should be removed as it is inaccurate. The studies performed for the Taskforce for winter 2016-17 and summer 2017 were **simply system capacity** calculations (i.e., how much demand the system could support without Aliso Canyon) and thus **were not the winter design standard or the summer peak EG condition, or any specific condition**. It was a short term analysis using only capacity calculations while the scenarios to be evaluated in this proceeding must be longer term and more complex to support overall system reliability. In addition, there were not "several iterations of the model" run at various levels as SoCalGas' hydraulic models were based on 100% utilization to maximize and determine what the capacity of our system is. This is described in the 2017 reliability assessment where it is explained in the gas assessment that 100% receipt point utilization was used in the analysis by SoCalGas. Later in the report, in the electric assessment, it was discussed that they took reductions in gas demand to replicate lower receipt point levels.

3) Initial Proposal at Page 4 (bottom of page): "Energy Division suggests using the Winter Peak Day Demand and the Summer High Sendout Day Demand forecasts in the most recent update to the California Gas Report."

   SoCalGas Proposed Revision: "Energy Division will utilize publicly available data to develop the winter peak day demand forecasts needed for the hydraulic modeling, consistent with SoCalGas' Commission-mandated design standards and other related guidance."

   Comments: As set forth above, the Commission established planning criteria and reliability standards for SoCalGas.[18] Specifically, the Commission ordered: "The reliability standard of 1-in-35 for core customers, 1-in-10 for noncore customers, and 1-in-35 for core local transmission customers is adopted for Southern California Gas Company (SoCalGas)."[19] The Commission also stated that : "the systems must be designed to provide service to core customers during a 1-in-35 year cold day event (one

[17] The 715 report should not be the determining factor because it is only a one season look.
[18] D.02-11-073, at 46 (Finding of Fact 16).
[19] D.02-11-073, at 49 (Ordering Paragraph 10).

curtailment event in 35 years) and service to firm noncore customers during a 1-in-10 year cold day event (one curtailment event in 10 years)."[20]

This standard was further clarified: "It is reasonable to require that each of the utilities plan its backbone system to meet one-in-ten year cold and dry conditions."[21] Also, and as set forth above, Mr. Sullivan (of the CPUC) required SoCalGas to achieve certain withdrawal rates to maintain electric (non-core) reliability for the summer. [22]

Further, based on the March 16, 2017 Letter and as discussed at pages 3-4 above, SoCalGas understands that the Commission expects, even in extreme conditions, SoCalGas to maintain supply to noncore customers.

Again, this understanding is supported by Energy Division proposing a design standard of 1-in-35 for core customers, and 1-in-10 for noncore customers. If SoCalGas' understanding is incorrect, it would be helpful to the parties for Energy Division to clarify the proposed planning standard that it plans to use for its modeling.

Currently, SoCalGas does not use a composite 1-in-35 year peak day demand for the core market segment and a 1-in-10 year cold day demand for the noncore segment in its design and modeling of the gas system. SoCalGas has two design standards: the 1-in-35 year peak day, where only the core market is served under that temperature condition and the non-core is fully curtailed, and the 1-in-10 year cold day, where the forecast core demand and noncore demand are fully served.[23] Further, if the proceeding is to set a new design standard, that should be part of the OII.

4) Initial Proposal at page 5 (top of page): "Currently, these forecasts do not extend beyond 2022. However, the Report states that SoCalGas expects total gas use to decline by 0.6% per year from 2016 to 2035. Energy Division proposes using the 0.6% expected annual rate of decline to forecast peak day demand in 2027."

   SoCalGas Proposed Revision: "Currently, the summer forecasts do not extend beyond 2022. However, the Report states that SoCalGas expects total gas use to decline by 0.6%

[20] D.06-09-039, at 49-50.
[21] D.06-09-039, at 171 (Finding of Fact 6). The Commission further stated in that decision: "We will also make explicit the requirement that the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems." (D.06-09-039, at 27). "It is reasonable to require that each of the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems." (D.06-09-039, at 171 (Finding of Fact 7)).
[22] March 16, 2017 Letter from Executive Director Sullivan to Rodger Schwecke (at page 1), available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/CPUCLettertoSoCalGasreStorageSafetyEnhancementPlan.pdf
[23] The table in the CGR simply lists the highest demand conditions expected by the core (e.g., that under the 1-in-35 year peak day standard), and by the noncore non-EG, and EG customer classes (e.g., that under the 1-in-10 year cold day standard), but the CGR erroneously totals these demands, implying that the design standards occur simultaneously, which is not the case.

per year from 2016 to 2035. Energy Division proposes using the 0.6% expected annual rate of decline to forecast peak day demand in 2027."

Comments: A 0.6% decline annually on average does not lead to a conclusion that the peak day is also expected to decline by 0.6% each year. Annual demand may decline while the peak day demand stays the same or even increases. In addition, although annual gas demand on the SoCalGas system is forecasted to decline, peak hour demand will likely go up due to renewable generation. The dispatch of gas-fired generation in response to increasing levels of solar generation is shown in CAISO's "duck curve," and demonstrate a rapid and significant increase in hourly gas demand once solar generation drops off between the evening hours of 4-7 pm. The model needs to reflect this current reality. Moreover, the Commission should use the most recent version of the CAISO "duck curve" and should request this data from CAISO.

5) Initial Proposal at page 13 (bottom of page): "The SERVM model produces 8,760 hourly profiles of operation for each of the gas-fired power plants. Energy Division will use these profiles to back out gas usage on several gas event days. *It will then give these inputs to the hydraulic modeling group to do a gas flow analysis*." (emphasis added for reference in comments)

Comments: This statement is inconsistent and requires clarification. Specifically, the Commission should clarify if the hydraulic modeling group will be using the demand forecast discussed previously or the SERVM output for its analysis. The SERVM output assumes the operation of Aliso Canyon, whereas the process for the hydraulic modeling starts with Aliso Canyon unavailable. SoCalGas believes this should be clarified to be made consistent in later iterations of the scenarios. Moreover, the PLEXOS model is the more appropriate model for electric market modeling, as set forth below.

The reason for this is that most industry standard generation dispatch or production cost simulation model (such as PLEXOS) are capable of simulating future power market dispatch while incorporating the interactions between technology, policy, regulation, and physical infrastructure of the power system. To more accurately or fully assess the impact of Aliso Canyon on electric market reliability and cost to consumers, the production cost simulation model should also have the following attributes:

- Nodal modeling capabilities to represent detailed transmission system flows and identify regional as well as local limitations of the system to deliver generation to load
- The capability to explicitly incorporate constraints on natural gas availability at a unit or system level due to the absence or reduced deliverability of Aliso Canyon
- The capability to represent a feedback loop between natural gas availability and cost with power system reliability and economics
- The ability to replicate key power market operations' attributes and processes such as
    - uncertainty between the day ahead market and the real-time market
    - scheduling and dispatching generation to support neighboring balancing authorities for energy and reserves

  - and coordination between gas and power markets
- The capability to represent both inter-temporal and sub-hourly constraints on the power-system that enhance the need for dispatchable generation and system flexibility provided by Aliso Canyon
- The ability to estimate the impacts of Aliso Canyon on Green House Gas (GHG) emissions

In sum, even if PLEXOS is not selected as the model, the model selected should have the above-listed attributes.

IV. Responses to Questions Posed in the Initial Proposal

Responses to Questions from pages 5-6 of Initial Proposal

1) Are the proposed modeling dates reasonable, i.e. 2018, 2022, and 2027?

   By the time the study for 2018 is performed and analyzed, it will be out of date and obsolete. Instead, SoCalGas suggests modeling April – March periods beginning in 2020, 2025, and 2030.

2) Is the proposed process for determining the minimum Aliso inventory level reasonable?

   SoCalGas does not believe the parties and the Commission should be setting a "minimum Aliso inventory level." Inventory is an outcome not an assumption; the needed withdrawal capacity will settle the needed inventory throughout any period. The standards should provide for sufficient flexibility and resiliency. What matters for a single day, multiple days, or seasonal use, is withdrawal rate; inventory levels matter for an extended period of time. SoCalGas submits that the Commission should determine the withdrawal rate needed for a single day / hour and the inventory necessary to support winter and summer needs for core and noncore customers, including balancing services. SoCalGas cannot use all of the inventory in a field on one day, and then have no inventory available for the remainder of winter (or next day), for example. Finally, consideration also needs to be given to the findings in the Sandia report, such as disaster relief from a large earthquake on the San Andreas fault that's projected to occur before 2030.

3) Is the California Gas Report the appropriate source for summer and winter peak day gas demand forecasts?

   Data in the California Gas Report may be used for the summer peak day demand forecast, but data for the winter peak day demand forecast is incomplete. SoCalGas also suggests requesting summer peak demand from the Balancing Authorities and CEC.

4) Is it reasonable to estimate 2027 gas demand by reducing the 2022 peak day forecasts by 0.6% per year?

   No. As has been discussed in these comments, studies indicate that the duck curve is getting steeper as the transition to more solar resources occurs. Further, peak day and hour demand may remain unchanged or even increase, even though overall annual demand is declining. This also results in a greater need to for flexible resources such as Aliso Canyon.

   a) If additional mitigation measures are put in place, would they result in a greater than 0.6% annual decline in gas demand?

      It will not be possible to determine whether a mitigation measure would impact demand on the peak day as set forth in the Initial Proposal.

   b) If so, what would be an appropriate method for forecasting future gas demand?

      The public utilities and State agencies are practiced at forecasting gas demand, and should carefully develop the forecasts needed for this important assessment. SoCalGas does not recommend "short-cutting" the forecast process by simply applying an assumed fixed reduction in demand. Gas demand should be based on hourly needs, such as that shown in CAISO's duck curve, and not an annual projection which is not useful.

5) Should historical gas days also be modeled?

   No. The framework is correct that peak day forecasts should be evaluated instead.

6) Is 85% gas receipt point utilization a reasonable assumption?

   As the Commission is aware, receipt point utilization is a market issue and is dependent upon the market participants – from upstream suppliers, shippers, and the core and noncore customers – to purchase, schedule, and deliver the gas. Receipt point utilization is primarily dependent upon customer demand and does not reflect actual historical receipts. Full receipt point utilization, for instance, only provides the upper bound of SoCalGas' ability to serve customer demand.

   Merely assuming a utilization for analysis like this oversimplifies the gas market and scheduling processes, and does not consider the variability that can occur. Hence, a probabilistic model should be developed to obtain the most accurate presumption. The model should take into consideration feedback from the economic models being developed. Notwithstanding, SoCalGas assumes – as set forth in the Initial Proposal (at page 5), that this 85% is a proxy for an appropriate contingency for what could happen. If that is the case, SoCalGas submits that 85% is not reasonable. The historical range of

60-80%[24] would be a better assumption. Regardless, it is highly unlikely that an 85% receipt point utilization would be realistic over the long period of time to be modelled, nor would the 85% receipt point utilization assumption be realistic to take into account future outages.

7) Is it reasonable to assume that SoCalGas will be restricted to tubing-only flow?

   Yes, it is reasonable that SoCalGas will be restricted to tubing flow only for all of its storage fields.

8) Are there any other inputs or assumptions that should be considered?

   California and much of the Western U.S. have only just emerged from a severe multi-year drought. Peak day EG demand under dry hydro conditions for both summer and winter seasons should also be examined. In addition, there is no accounting for the number of storage field wells that may be available being available or available inventory levels, which would impact the available withdrawal rates. Furthermore, system resiliency should be accounted for as SoCalGas needs to be able to temporarily remove parts of the system from service for scheduled work (e.g., TIMP, PSEP, SIMP).[25] It bears emphasizing that this is not an exhaustive list but is illustrative of the type of holistic factors that need to be accounted for in the model.

9) Are there any other questions that should be considered?

   What assumptions will be made regarding the core's ability to replenish/use storage withdrawals to maintain sufficient inventory going into and throughout the winter season?

<u>Responses to Questions from Page 11 of Initial Proposal[26]</u>

1) Are the inputs described above appropriate for use in the model as described?

   The inputs described above in regards to the status of Aliso Canyon are inconsistent with the proposed hydraulic modeling process as discussed in Section II and III above.

6) What is the best methodology to translate inventory at Aliso, Playa del Rey, and Honor Rancho to withdrawal rates / rate of delivery to the 17 power plants?

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[24] Winter 2016-17 Technical Assessment p.29; see also, Initial Proposal at p. 5.

[25] See, D.16-12-009. In addition, the scoping ruling in the 2016 PSEP reasonableness review requires comments on pipeline maintenance projects "to be deferred." A. 15-06-013, Scoping Memo at pp. 1 and 4.

[26] SoCalGas incorporates its general comments to questions 2 through 5 on page 11 of the Initial Proposal.

Service continuity to the Los Angeles basin power plants cannot be evaluated separately from the other SoCalGas customers. The entire system needs to be modeled, because it is possible that power plants besides the 17 listed as being served by Aliso Canyon will be effected. For example, if natural gas must be brought into the Northern System/LA Basin to serve the 17 power plants with flowing supplies due to Aliso Canyon being out of service, it is possible that the flowing supplies will be diverted from other power plants and the SoCalGas' southern system will be curtailed, as natural gas would flow towards Los Angeles and not San Diego.

Responses to Questions from Page 12 of Initial Proposal

1) Are the proposed modeling dates reasonable?

   SoCalGas incorporates its comments and responses from above.

2) Are the proposed Aliso inventory levels appropriate?

   SoCalGas incorporates its comments and responses above.

3) Is it reasonable to model low, mid, and high forecasts of natural gas prices?

   Gas price forecasts are likely to be annual averages or monthly averages. Daily and intra-day gas price forecasts may need to be developed to properly model impacts. Impacts to regional gas prices (e.g. price spikes) should consider competition from other southwest gas demand, such as increasing Mexican exports and Gulf of Mexico LNG U.S. exports. It should also consider reduced supply availability due to well freeze-offs or major outages of interstate pipeline capacity. This would be consistent with Staff's Public Comment Summaries and Responses on p. 17 Appendix A of the report issued by the Public Utilities Commission pursuant to Public Utilities Code section 715 on July 19, 2017, entitled, *Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity, and Well Availability for Reliability*.[27]

4) Is there an existing gas price forecast dataset that would be appropriate to use in this model?

   For consistency when evaluating results, the same gas price forecasts should be used for all studies.

5) Are there any other inputs or assumptions that should be considered?

   With reduced core storage inventory, costs for acquiring seasonal versus annual interstate capacity for the core customers are greater and should be considered. Also, SoCalGas

[27] Available at:
http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/ReportReliability.pdf

recommends that modeled reductions to allocated core storage inventory be done in increments to help identify the marginal benefits of additional Aliso Canyon inventory.

6) Are there any other questions that should be considered?

   The economic analysis should also consider the impact on electricity prices and rates to end-use customers, including the economic impact on rates resulting from the development and deployment of electric storage solutions – particularly if these are going to be key in maintaining electric system reliability without the use of Aliso Canyon.[28] This assessment should also assess the long-term risks and costs associated with electric storage solutions, such as the operating risks associated with batteries and the disposal of spent batteries.

   Furthermore, if the use of Aliso Canyon is reduced or eliminated, the core will lose flexibility and will likely need to enter into firm transportation contracts. The costs of these firm transportation contracts must be considered in the model.

   In addition, SoCalGas queries whether the Aliso Canyon inventory is going to be made available for core and/or noncore scheduled withdrawals during non-extreme demand events? Furthermore, the Commission should clarify what assumptions are being made regarding storage available to noncore customers under different Aliso Canyon inventory scenarios.

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SoCalGas appreciates the opportunity to submit comments to the Initial Proposal and the Commission's consideration of the issues identified in this letter and at the workshops in this proceeding.

Sincerely,

/s/ Sabina Clorfeine

Sabina Clorfeine
Assistant General Counsel
SOUTHERN CALIFORNIA GAS COMPANY

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[28] Notably, as observed in the Sandia Report, it was stated that "The role of natural gas storage, in general, is to provide a buffer between constant production and the highly seasonal nature of consumption. In this case, Los Angeles is fortunate to have Aliso Canyon storage facility in its backyard. At roughly 85,000 mmcf of working (or usable) gas capacity, this storage facility is one of the largest in the United States." (Sandia Report, at p. 12. Available at http://prod.sandia.gov/techlib/access-control.cgi/2013/134938.pdf)

ATTACHMENT B

COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G)

SoCalGas
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June 28, 2018

BY E-MAIL
(AlisoCanyonOII@cpuc.ca.gov)

California Public Utilities Commission
Energy Division
505 Van Ness Avenue
San Francisco, CA 94102

RE: Southern California Gas Company's Response to Update to the Scenarios Framework (Investigation 17-02-002)

Dear Energy Division Staff:

Pursuant to the Administrative Law Judge's Ruling Requesting Informal Feedback on Energy Division's Updated Proposed Phase 1 Scenarios dated June 15, 2018, the Scoping Memo and Ruling of [the] Assigned Commissioner and Administrative Law Judge dated June 20, 2017 ("Scoping Memo"), and the Administrative Law Judge's Ruling Adopting Updated Phase 1 Schedule dated May 23, 2018 (the "Updated Schedule"), Southern California Gas Company ("SoCalGas") submits its Informal Comments on Energy Division's Update to the Scenarios Framework (the "Updated Proposal").[1] SoCalGas understands the Updated Proposal is being conducted for developing preliminary scenarios related to the future use of Aliso Canyon pursuant to Public Utilities Code section 714 and I.17-02-002.

I. INTRODUCTION

This proceeding has potential long-reaching impacts on energy reliability both within Southern California and in the surrounding Western Region of the United States. Just as weather and market events outside of California can impact the price and availability of California's natural gas supply, regulatory decisions in California can influence market conditions in the entire Western Region in addition to impacts on California itself. As such, taking Aliso Canyon out of the market will reduce natural gas supply, reduce competition, and increase prices. Against this backdrop, it is incumbent upon Energy Division (and the Commission) to

[1] Energy Division's Initial Proposed Phase 1 Scenarios, dated June 26, 2017 is referred to herein as the "Initial Proposal."

transparently create a scenarios framework with a developed record and hearings, culminating with a formal Commission decision.

Relative to the Updated Proposal, SoCalGas has several recommendations which are set forth in greater detail below. Throughout the Updated Proposal, however, Energy Division notably does not define when it believes a model run has been "successful." The importance of defining "success" cannot be overstated for a proceeding so heavily dependent on running models. Absent such clarification, Energy Division and the parties will not have any method of determining the import of any particular executed scenario. In sum, Energy Division should propose a set of goals or requirements that would indicate when a model has succeeded. Then, using those criteria, Energy Division should determine whether those criteria can be met under specific circumstances, including planning for contingencies on the gas and electric system.

SoCalGas appreciates the opportunity to comment upon the Updated Proposal. As set forth below, there are procedural issues and general comments which should be addressed by the Commission and Energy Division, and, thereafter, SoCalGas has comments regarding the hydraulic modeling, production cost modeling, and economic modeling set forth in the Updated Proposal.

II. GENERAL COMMENTS ON THE UPDATED PROPOSAL

a. The Commission Should Provide for Hearings, Evidence, and a Commission Decision in Phase 1

This proceeding is about future energy reliability and costs for customers in California and surrounding states. Because of the importance of this determination, Phase 1 should be resolved through a formal Commission decision with appropriate findings of fact and conclusions of law. Given the significance of the issues involved, relying on an informal process to determine scenarios to be modeled, assumptions and other inputs, is insufficient. Assumptions made for the Phase 1 analysis of this proceeding will have long-term ramifications for energy reliability in Southern California and beyond. Therefore, hearings should be conducted for Phase 1 of this proceeding.

b. The Scenarios Should Assume Compliance with Applicable Laws and Regulations

The Updated Proposal states that "[t]he inputs into the models will be based on demand projections that incorporate all the increases in renewables, conservation, and energy efficiency currently required by California legislation."[2] SoCalGas supports this requirement. This proceeding should not be about potential, imaginative, or proposed policies or overly optimistic forecasts. As such, Energy Division should be careful to limit inputs and assumptions to current requirements. Additionally, SoCalGas suggests that the model inputs incorporate and comply with current operational and safety regulatory requirements. Such requirements include, for example, (1) well deliverability reductions resulting from the conversion and operation of

[2] Updated Proposal at p. 4 (emphasis added).

storage wells in tubing-only-flow configuration; (2) additional storage well and facility planned outages throughout the year as a result of more frequent facility shut-ins to assess inventory; and (3) increased well integrity assessments, and the potential for reduced facility capabilities as a result of a reduction in the number of wells through plug and abandonment requirements.[3]

c. The Commission Should Clarify the Scope of Phase 1 and its Relationship to Phase 2

The Updated Proposal states that, "In Phase 1, the Commission will undertake a comprehensive effort to develop the appropriate analyses and scenarios to evaluate the impact of reducing or eliminating the use of Aliso [Canyon]. The intent of Phase 1 is to involve all interested parties in developing a transparent and vetted list of assumptions and scenarios. Phase 1 will be resolved by the issuance of an Assigned Commissioner's Ruling providing guidance on the scenarios and assumptions that will be evaluated in Phase 2. In Phase 2, the Commission will conduct the analyses agreed to in Phase 1 and evaluate their results."[4]

The Updated Proposal's use of words like "vetted" and "agreed to" with respect to the Phase 1 results suggests that these will binding with respect to the modeling undertaken in Phase 2. The Updated Schedule, however, states that parties will have an opportunity to present alternative modeling approaches as part of Phase 2. The Commission should confirm that in Phase 2 parties will not be barred from contesting the reasonableness of all scenarios, assumptions and any other element of the Phase 1 models.

While the Updated Proposal defines the scope as Phase 1 scenarios and assumptions, it appears to more broadly define the logic of the modeling that will be undertaken. Provided that the Commission confirms that parties will have an opportunity to examine and contest all issues as part of Phase 2, this may not be an issue. Otherwise, additional process on the modeling framework should be permitted.

d. The Commission Should Clarify SoCalGas' Dual Role (and Associated Rights and Responsibilities) in this Proceeding

Due to the Commission not engaging a modeling consultant to perform the hydraulic modeling, SoCalGas has been ordered to perform this function, under the direction of the Commission's Energy Division and subject to the oversight of Los Alamos National Lab ("Los Alamos"). At the same time, SoCalGas is a party to this proceeding. As the hydraulic modeler for the Commission, SoCalGas will run the model based on the inputs, parameters, and assumptions identified by Commission staff. As a party, however, SoCalGas must be permitted to contest the reasonableness of those assumptions, in comments or at the workshop, like any other party. In addition, SoCalGas reserves the right to present an alternative model as part of

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[3] Division of Oil, Gas, and Geothermal Resources ("DOGGR") Requirements for California Underground Gas Storage Projects, outlined in 14 California Code of Regulations ("CCR") § 1724.9. Gas Storage Projects, and proposed new Article 4. Requirements for Underground Gas Storage Projects DOGGR 14 CCR § 1726 with subsections 1726.1. through 1726.10.
[4] Updated Proposal at p. 5.

Phase 2. SoCalGas' performance of its duties as a hydraulic modeler for the Commission should not be interpreted as either SoCalGas' agreement with, or endorsement of, the Commission's hydraulic modeling approach and assumptions or waiver by SoCalGas with respect to any issues that it may raise in connection with the hydraulic model that it performs at the Commission's direction.

e. Energy Division Should Clarify the Sequence of Modeling

Energy Division does not state in the Updated Proposal the sequence of the modeling (i.e., if hydraulic will run first, etc.) for the scenarios. Energy Division should clarify the order that this modeling will be done. As SoCalGas has stated, electric generator demand and hourly usage profiles are required for hydraulic simulation, and SoCalGas assumes that will be provided through use of the production cost model.

f. The Updated Proposal Should be Modified to Correctly Describe Aliso Canyon's Role and Benefits

In explaining Aliso Canyon's role in the system, the Updated Proposal states that "[w]hen daily gas load is higher than the pipeline flowing capacity, gas is withdrawn from storage at Aliso to serve the load that exceeds flowing supply. This functionality is possible because Aliso is close to the major gas load centers and the incremental gas added from Aliso withdrawals does not compete with the flowing supply for pipeline transportation."[5] While SoCalGas agrees with the first part of this statement, it is incorrect to state that gas withdrawn from Aliso Canyon "does not compete with the flowing supply for pipeline transportation."

As with any other supply, withdrawals from Aliso Canyon physically impact the receipt of pipeline supply. Over the course of the operating day, customer demand will change; if withdrawal from Aliso Canyon were held at a constant rate throughout the day, other supplies – such as pipeline supplies – would need to be reduced when demand dropped. Aliso Canyon supplies, therefore, do impact the receipt of other supplies.

g. Energy Division Should Clarify How It Will Document the Modeling Process, How to Determine Whether a Simulation is "Successful," and What is Required as an Output

Energy Division should clarify how it will document the modeling process and how it will determine if a scenario was "successful." For example, when SoCalGas performs a hydraulic modeling of its system, it is successful only if all operating parameters are maintained (minimum and maximum pressures and facility capacity limitations), linepack is fully recovered for the entire system and for all sub-systems (such as the Los Angeles Basin and the Southern System) to account for multi-day periods of high demand, and customer demand is met without reduction to demand to meet the other conditions for success.

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[5] *Id*. at p. 7.

Similarly, to promote transparency, Energy Division must define what it means for a simulation to be a "success." Each scenario to be simulated by SoCalGas must include documentation of all inputs, assumptions, any "additional actions,"[6] and the conditions that define success. Further, the Energy Division must explicitly state what output is required from each simulation to document the findings and allow SoCalGas and Los Alamos to fulfill their roles. Energy Division should formally document and describe the scenario being modeled. This formal documentation of each scenario is necessary for transparency, to allow scenarios to be compared, commented upon, and to allow scenarios to be challenged in Phase 2.

h. The Proposed Framework for the Reliability Assessment Introduces Increased Risk to Southern California Customers

The Proposed Framework for the Reliability Assessment prioritizes interstate pipeline supplies over storage supplies, to the extent of filling receipt points to as much as 95% of their firm capacity. If the purpose of the Reliability Assessment is to determine the "appropriate" level of storage supplies needed for 1-in-10-year cold day design standard, and the utility maintains only that identified level, there will be no contingency available when the interstate pipeline supplies are not delivered to the SoCalGas system. The SoCalGas system is almost wholly dependent on out of state deliveries of gas, with no meaningful in-state production. Lack of deliveries by the interstate pipelines can occur for a variety of reasons, such as extreme weather events outside of California, outages on the interstate pipelines and supply basin systems, or increased demand east of California, all of which are beyond the control of SoCalGas and the Commission. The Energy Division should include contingency storage supplies in this evaluation to address these risks, independent of any contingency reserved for on-system facility outages. Scenarios must be considered for a reduction in supplies from the interstate pipelines regardless of the base assumption of receipt point utilization.

i. The Commission Should Consider Impacts Beyond California

Aliso Canyon is a critical component of energy reliability, not just in California, but throughout the western United States. Accordingly, the Commission's analysis should not be limited to impacts within California. Weather and market events outside of California can and have impacted the price and availability of California's natural gas supply, and the loss of storage in California can impact prices and reliability in neighboring states. In turn, those effects in neighboring states can have an effect on supplies and cost in California.

For example, weather and market events east of California can cause supply shortages and/or demand spikes between the supply basins in Texas, New Mexico, Colorado and SoCalGas' service territory. Because there is no gas storage between the Permian Basin in Texas (where most supplies for the Southwest originate) and SoCalGas' storage facilities in and around Los Angeles, the states along the Permian to Los Angeles supply line rely almost entirely on flowing natural gas pipeline supplies.

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[6] SoCalGas offers additional comments on these "additional actions" below.

A facility the size of Aliso Canyon not only supports significant local customer demand but also creates a system that is flexible enough to displace gas to support surrounding states and regions. Recent history has demonstrated the importance of local natural gas storage not only to California's reliability, but also to the reliability of neighboring states.

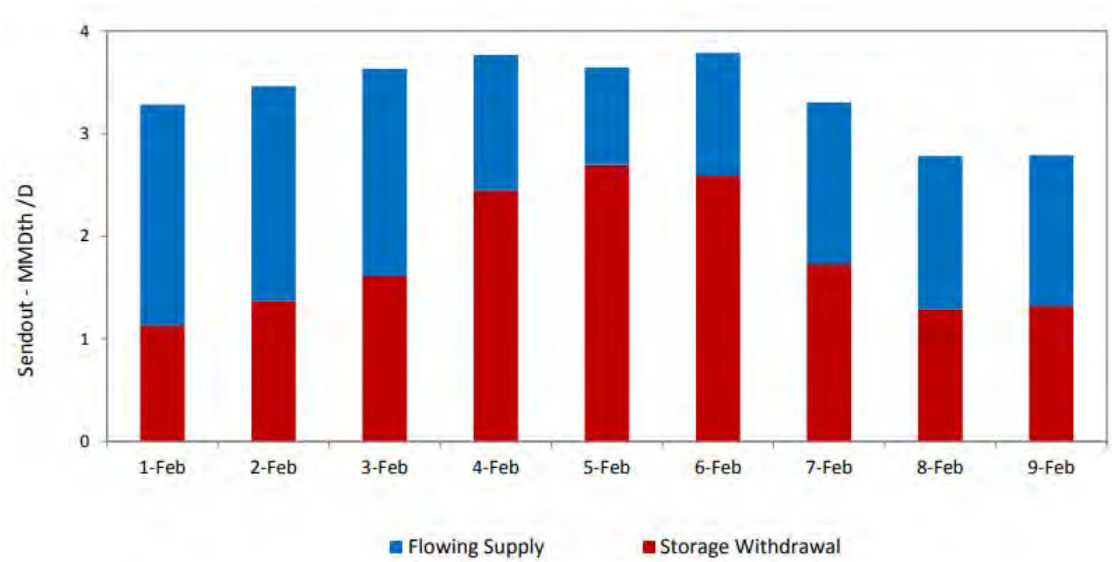
In early 2014, North America experienced an extreme weather event, where average temperatures in much of the lower 48 states fell significantly below normal (colloquially called the "Polar Vortex"). California, by contrast, experienced unusually warm and dry weather for that time of year. However, because average temperatures outside California fell considerably, gas demand in the impacted areas increased significantly. This was compounded with freezing temperatures in and around the Permian Basin, causing well freeze-offs and power outages, and further exacerbating the supply shortfall.

When high demand outside California created negative spreads between Southern California and upstream supply basins, marketers began diverting supplies to higher-valued markets east of California and receipts into the SoCalGas system began to fall. To illustrate the differences in market conditions, the below table provides approximate prices for various areas on February 6, 2014:

Location	**Approximate $ per MMbtu**
Rockies	$30
Permian	$24
San Juan	$21

PG&E CG	$22
SoCal-CityGate	$12

As gas was diverted to those higher-priced markets outside California, SoCalGas' receipts declined sharply and SoCalGas relied heavily on storage withdrawals to support system reliability. SoCalGas withdrawals reached 2.5 billion cubic feet or 73% of daily natural gas send out.



During this time, SoCalGas' Gas Acquisition department redirected some of its firm natural gas supplies to the higher-priced markets, thus helping to support states east of California that were hard hit by the extreme weather conditions and reducing core procurement ratepayer costs. During this event, SoCalGas' system was essentially an "energy island" due to the robust capability to withdraw natural gas from storage.

Absent the ability to withdraw gas from local storage, SoCalGas' customers would have had to potentially compete for gas supply to maintain reliable service at a time when market prices were spiking.

Nationwide electric and natural gas issues like those seen during the Polar Vortex may become more pronounced. Attached to SoCalGas' comments as Exhibit A is the June 2018 Western Interconnection Gas – Electric Interface Study (the "WECC Study"). The WECC Study found that the Western Interconnection (a wide area synchronous grid stretching from Western Canada south to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains) was at risk of being pushed to the limit: "Up until 2015, Aliso Canyon's 86 bcf of market-area gas storage and 1.8 bcfd of withdrawal capacity were historically sufficient to balance system variability in the Southern California region. However, the operational limitations imposed on Aliso Canyon are now highlighting several issues that were previously masked; SoCalGas is now effectively in an N-1 scenario with any major disruptions in the gas transmission system or the Bulk Power System (BPS) pushing the system to the limit."[7] The report goes on to note: "System reserve margins are expected to become increasingly tight through 2026…natural gas demand for power generation across the Western Interconnection [is forecast] to increase by 30% by 2026" and "[t]he configuration of the gas-electric system combined with the retirement of Aliso Canyon creates region-wide reliability issues, resulting in widespread loss of electric load; the Southwest and Southern California regions appear to be most vulnerable to major disruption events due to (1) heavy reliance on gas generation to meet peak demands, and (2) limited gas storage capability."[8] Again, a Commission decision to reduce or eliminate Aliso Canyon will have far reaching and significant effects on regional energy reliability and costs.

Therefore, the Commission's analysis of the benefits of Aliso Canyon should not be limited to its impacts to Southern California, but also to price impacts outside of Southern California, the reduction to reliability and flexibility it creates for neighboring states and the secondary impact of those conditions back in California.

III. COMMENTS TO THE HYDRAULIC MODELING IN THE UPDATED PROPOSAL

The Updated Proposal indicates that, as part of the Hydraulic Modeling, the Commission will undertake a Reliability Assessment and a Feasibility Assessment. These are addressed below, followed by comments to Energy Division's statements regarding "Drawing Conclusions from Monthly Gas Injection/Withdrawal Schedules."

The Updated Proposal provides that the assessments will cover the following:

- The Reliability Assessment will assess natural gas delivery system performance with allowable operational actions to achieve reliability standard conditions.
- The Feasibility Assessment will determine if the monthly minimum storage volume targets determined by the Reliability Assessment can be maintained throughout the year.[9]

As part of this analyses, the Commission plans to examine the Near-term (2019) with full monthly analysis, and Mid-term (2024) and Long-term (2029) on only peak Winter and peak Summer months.

# of Scenarios	2019	2024	2029	Total
Reliability	12	2	2	16
Feasibility	12	2	2	16

[7] The "N -1" condition requires electric operators to plan their system to have sufficient resiliency to lose a critical component and continue operating.
[8] SoCalGas notes, and as the Commission knows, it has not been decided to retire Aliso Canyon.
[9] Updated Proposal at pp. 9-10.

Before addressing the technical aspects of the proposed Reliability and Feasibility Assessments, SoCalGas notes the following items of general applicability:

First, the currently proposed modeling as the "near" term scenario is identified to occur in 2019. It would make more sense to model the next year, 2020. Otherwise the Commission could potentially find itself modeling a hypothetical 2019 scenario against the backdrop of actual 2019 operations. Furthermore, there would be little point in examining a "near-term" scenario that has already passed. For the near-term scenario, whether 2019 or 2020, the Commission should include all actual outages on the system and model the system as it is expected to exist at that time, rather than modeling based on the assumptions and factors used for the mid and long-term models.

Second, Energy Division states that it plans to run 32 scenarios.[10] Energy Division and all parties should be aware that completing and documenting a hydraulic model is no small undertaking, and will likely take 1-3 weeks for each run. To the degree that staff or parties modify scenario parameters or assumptions, it will require running those modifications as a separate scenario and will add additional time. As such, Energy Division should develop a process to document modifications or additional actions to a scenario. Further, to address these timing and resource demands, Energy Division should perform monthly mass balances for the Feasibility Assessment, similar to the mass balances that the Energy Division performed in its June 15, 2018 draft update to the 715 Report, instead of requiring hydraulic modeling. (Mass balances essentially is that the mass that enters a system must, by conservation of mass, either leave the system or accumulate within the system.) Performing hydraulic modeling on average day scenarios, and then assuming that each day of that month will be identical to the simulated day just so that a month-end system inventory level can be estimated, provides no more value than a mass balance and requires significantly greater time and resource requirements.

Third, with regard to receipt point utilization, the Updated Proposal appears to indicate that 95% receipt point utilization should be assumed.[11] This assumption is unreasonably high and does not reflect actual experience on the system. Receipt point utilization should reflect actual historical averages, which would be closer to 80%-85% utilization. If a 5% deficit is to be selected, then the Commission must conclude that Daily Balancing should be imposed with a 5% tolerance. This is the only way that SoCalGas believes customers will attempt to meet a 95% receipt point utilization. However, it is difficult to reasonably assume that customers will adhere to that assumption on a physical basis when economic factors could drive supplies to be delivered elsewhere leaving California well short of the 95%.

Fourth, for purposes of hydraulic modeling the electric generation load, SoCalGas will need to know <u>hourly</u> demand for each specific plant, and assumes that this resolution will be available from the production cost model prior to any hydraulic modeling.

Fifth, in addition to the proposed outage analysis, Energy Division should provide additional scenario analysis of emergency situations and potential upstream supply disruptions

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[10] Updated Proposal at pp. 18-19.
[11] *Id.* at p. 13-14.

and the unexpected loss of electric imports. Upstream supply disruptions on the interstate pipelines systems can occur during the winter or summer, creating a loss of deliverability to the SoCalGas receipt points. Aliso Canyon's ability to deliver directly into the Los Angeles basin can mitigate the sudden temporary or even a prolonged loss of gas supplies at the border for a period a time until other interstate pipelines can properly compensate for the loss. An unexpected loss of electric imports would create the emergency need for in-basin gas fired generation to avoid a loss of load event. Given the storage inventory at Aliso Canyon, and its proximity to the Los Angeles Basin, gas supplies can quickly be withdrawn to balance the ramp in gas consumption from generators mitigating the loss of electric imports.

Indeed, local natural gas supply sources are an important system resiliency, emergency response, and incident mitigation tool. California receives approximately 90% of its natural gas from out of state. Underground natural gas storage provides in-state stockpile of supply in case of climate change related emergencies, such as worsening wildfires.[12] As recognized by the California Council of Science and Technology, natural gas storage facilities could increasingly be called on to provide gas and electric reliability during emergencies caused by extreme weather and wildfires, which are expected to increase with climate change.[13]

a. Comments on the Reliability Assessment in the Updated Proposal

i) The Updated Proposal's "Preference" for Non-Aliso Canyon Storage Fields Does Not Reflect CAISO's Current Economic Dispatch Requirements

The Updated Proposal states that the "key analysis task is the determination of the minimum level of gas in underground storage needed to maintain reliability of both energy systems and to maintain just and reasonable energy rates."[14] Energy Division further states that "preference" will be given to operations of non-Aliso Canyon storage facilities to determine the minimum need for gas storage inventory at Aliso Canyon.[15] What exactly this means in practice, however, is unclear, and moreover, it does not reflect current electric dispatch as determined by CAISO. Given the comprehensive safety review and enhancements that have been implemented at Aliso Canyon, it does not make sense to "prefer" some assets over the use of other assets, especially when it is not consistent with current practice.

The Updated Proposal also provides that non-Aliso Canyon gas withdrawals will be used first to meet peak day gas demand.[16] Here, SoCalGas submits that Energy Division clarify the storage injection/withdrawal and inventory assumptions to be used for non-Aliso Canyon storage fields. In the Initial Proposal, Energy Division proposed to use only maximum tubing-only-flow

[12] California Council on Science and Technology Long-Term Viability of Underground Natural Gas Storage in California; An Independent Review of Scientific and Technical Information ("CCST Report"), p. 626.
[13] *Id.* at 506.
[14] Updated Proposal at p. 6.
[15] *Id.*
[16] Updated Proposal at p. 12.

storage withdrawals from non-Aliso Canyon storage fields, and Energy Division should confirm that this assumption remains the standard.[17]

ii) Comments Regarding Energy Division's 1-in-10 Year Analysis

Energy Division states that for its 1-in-10 Year Analysis, there will be no curtailment of any gas load (core; non-core, non-electric; or non-core, electric) allowed in the analysis, and that electric loads will be based on normal operations of the electric grid.[18] Energy Division further states that for the non-core, electric gas load, for 1-in-10 economic optimal production cost model with no gas supply constraints and "meeting minimum NERC reliability standards."[19] Here, SoCalGas submits that a 1-in-10 Dry Hydro year load be used, similar to what Energy Division had proposed in the Initial Proposal.[20] As designed, the 1-in-10 analysis is not subject to gas availability constraints, and, instead, the demand for gas from electric sector should reflect a normal economic dispatch of within basin generators assuming gas availability, similar to the "As Found" Production Cost Modeling study outlined on page 22 of the Updated Proposal. No restrictions on generators within the basin should be applied to derive the electric demand.

iii) Comments Regarding "Minimum Gas Storage Schedule"

Energy Division also states in the Updated Proposal that it will utilize the monthly analysis to determine a "Minimum Gas Storage Schedule" for each period in 2019 and peak summer and winter months for 2024 and 2029.[21] Here, Energy Division should clarify whether the minimum gas storage schedule reflects withdrawal performance declines that are associated with inventory decreases, and injection performance declines that are associated with inventory increases at each storage field.

iv) Comments Regarding "Maximum Available Scheduling Capacity"

Next, Energy Division states that it is considering the use of a 5% deficit relative to maximum available scheduling capacity.[22] Here, while SoCalGas believes this is an unreasonable assumption, clarification is needed as to what is the "maximum available scheduling capacity" as set forth in the Updated Proposal and how it relates to the Initial Proposal's proposed 85% gas receipt point utilization.[23] Specifically, Energy Division should clarify if this is a receipt-point specific value or an overall cumulative utilization factor that is independent of receipt location.

[17] Initial Proposal, at p. 5.
[18] Updated Proposal at p. 8.
[19] *Id.* at p. 11.
[20] Initial Proposal at p. 4, fn. 5.
[21] Updated Proposal at p. 10.
[22] *Id.* at p. 14.
[23] Initial Proposal at p. 5.

v) Comments Regarding Outages

Energy Division states that it will examine a single plausible unplanned outage that results in the maximum loss of aggregate gas send out.[24] SoCalGas agrees that incorporating loss of capacity due to outages is important for purposes of the Reliability and Feasibility Assessments. Energy Division proposes to use historical analysis from the 2016 Aliso Canyon Risk Assessment Technical Report (Table 3) to determine the range of a single unplanned outage (The range of outages considered was 150-900 MMcf/d).[25] SoCalGas recommends that the outage analysis reflected in the 2016 report be updated from the 2013-2015 period to include the latest line outages in 2017 (Line 3000, 4000, 235-2). Furthermore, Energy Division should clarify the assumption regarding the comparison of the largest unplanned outage at Aliso Canyon versus the largest plausible non-Aliso Canyon outage.[26] The outage analysis should examine the potential mitigating impact Aliso Canyon may have during an unplanned outage, i.e., to test the ability of the system to withstand the largest unplanned outage, with and without the benefit of Aliso Canyon. Moreover, an unplanned outage is just that – "unplanned" – and could occur at any of the storage fields at a particular time. To somehow use an unplanned outage at Aliso Canyon rather than factoring in an unplanned outage at another storage field just because the impact is larger does not properly address the impact of another storage fields outage in determining the long-term need for Aliso Canyon.

While historical outage records serve as a good starting point for such analysis, the correlation between historical outages and future outages is weak. Pipelines and other infrastructure continue to age and diagnostic equipment technology continue to advance, more accurately identifying maintenance issues in need of attention. As the technology advances, it is anticipated that the technology will increasingly identify issues that were not apparent before, but are now in need of maintenance. That combination means that there will likely be more outages in our future than in the past. Accordingly, the Commission should perform some form of sensitivity analysis to determine the impact not just of a single outage but to also capture the effect of a potential multiple outage scenario.

Additionally, the Updated Proposal's description of how unplanned outages will be applied during the Reliability Assessment should be clarified. It appears to suggest that the largest plausible unplanned outage will only be assessed if the Reliability Assessment shows that withdrawals from Aliso are required. The rationale of such an approach, however, is not sufficiently explained. Depending on how it is implemented, this approach could fail to accurately capture the impact of the unplanned outage. The effect of the unplanned outage thus should instead be assessed on the system *before* determining whether withdrawals from Aliso Canyon are needed.

[24] Updated Proposal at p. 14. The Feasibility Assessment would also include planned outages.
[25] *Id.*
[26] *Id.* at p. 15.

vi) Comments Regarding Potential Analysis Beyond the Reliability Assessment

The Updated Proposal states that "[t]he Reliability Assessment may return a result that does not meet the required natural gas delivery performance, even when implementing the full set of allowable operational actions. In this case, a sensitivity analysis may be performed to estimate what additional actions may be taken beyond the set of operational actions defined by the reliability standard."[27] This suggests that if the result of the Reliability Assessment, for a specific scenario, shows that reduced reliance on Aliso Canyon will result in a loss of load, or result in an otherwise unsuccessful simulation, the Commission will consider undefined "additional actions" that could potentially alter the outcome and preserve reliability. The discussion of "additional actions" here requires further definition and explanation. Would this include LNG procurement to support system demand? What might be the safety implications of these actions? Would these include mitigation measures like energy efficiency and alternative infrastructure like new pipeline or storage capacity? If so how and when will the Commission evaluate the reasonableness, feasibility and cost-effectiveness of such additional actions? These are issues that should be addressed in hearings in Phase 1 of this proceeding where these and other questions can be addressed and parties could create a formal record and justification for such actions.

b. Comments on the Feasibility Assessment in the Updated Proposal

In the Updated Proposal, Energy Division states that the flowing supply available is assumed to be 5% lower relative to the maximum available scheduling capacity.[28] SoCalGas recommends that Energy Division expand upon this assumption and rationale of lowering by 10% from the Initial Proposal the maximum available scheduling capacity utilized. Monthly average utilization is a function of the system sendout capacity, which includes customer demand and available storage capacity (inventory, injection, and withdrawal). Gas supply in excess of the system sendout capacity cannot be received; therefore, this proposal is only feasible if the Energy Division intended that "maximum available scheduling capacity" equals actual system sendout capacity.

The Energy Division also states that it will examine typical system conditions on a monthly basis to assess nominal available gas storage injection/withdrawal rates for nominal monthly operations.[29] SoCalGas submits that Energy Division should build into the Feasibility Assessment the injection curves so that Energy Division can see whether the system still has injection capacity as the storage fields fill up or are unavailable due to unplanned outages or planned required maintenance.

Next, Energy Division states that its outage assessment will review historical outages and determine the magnitude of planned and unplanned outages on monthly injection and withdrawal capabilities over the year. In this context, SoCalGas recommends that known planned outages be

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[27] *Id.* at p. 9.
[28] *Id.* at p. 18.
[29] *Id*. at p. 17.

incorporated into the proposed analysis, to better understand the availability of the Southern California system's ability to inject and withdraw gas. Without including known planned outages into the proposed analysis would paint an unreasonable long-term expectation that all non-Aliso Canyon capacities are available at their maximum capacities as they exist today under ideal circumstances.

c. Comments on "Drawing Conclusions from Monthly Gas Injection/Withdrawal Schedules"

In the Updated Proposal, Energy Division states that it will determine the largest minimum storage requirement at Aliso Canyon and that for any year, if the scenarios are found to be greater than zero, Aliso Canyon must remain open, unless alternative operation actions, or supply is added.[30] In this regard, Energy Division should clarify what alternative operation actions or supply sources it is considering. The feasibility, cost, reliability and safety implications of these alternatives as well as their potential impacts on gas and electric ratepayers need to be assessed by the parties to this proceeding.

IV. COMMENTS TO THE PRODUCTION COST MODELING IN THE UPDATED PROPOSAL

Energy Division proposes to begin with the 715 Report inventory level, which it describes as "the range of Aliso necessary to ensure safety, reliability, and just and reasonable rates."[31] SoCalGas submits that the inventory level should begin with 68.6 Bcf, because that was the inventory level determined by DOGGR. Additionally, to compare against the economic benefit of gas storage, there must be a scenario where storage withdrawal is maximized.

Furthermore, the Energy Division's Production Cost Model does not identify many of its inputs and assumptions. For example, the production cost model in the Updated Proposal does not identify – and should identify – the demand, import capacity, outages, and wildfire risk in its assumptions. Energy Division should also clarify if it will be performing an economic dispatch or some other financial analysis.

Energy Division states that it will use the SERVM model to simulate electric generation dispatch to create the 1-in-10 reliability standard day, 1-in-10 summer peak day, and 1-in-35 winter gas demand day.[32] Here, SoCalGas recommends maintaining the 1-in-10 Dry Hydro standard in the "As Found" Case with no initial curtailment or re-dispatch of in basin generation needs.

Energy Division also provides that it will restrict only the 17 power plants linked to Aliso Canyon to simulate the effect of more distant gas delivery.[33] SoCalGas recommends that Energy Division should project the hourly dispatch of the remaining power plants on the Southern California system, in addition to the proposed 17 power plants, as those facilities also receive gas

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[30] *Id*. at pp. 18-19.
[31] *Id*. at p. 23.
[32] *Id*. at pp. 21-22.
[33] *Id*. at p. 20.

supply from Southern California and are also impacted by Aliso Canyon. Assuming only the 17 plants is not consistent with an assessment that looks at the entire system requirements as all other scenarios consider – including the hydraulic modeling of the system. This is not a Los Angeles basin issue, but an entire system issue and to limit it would be unreasonable. In addition, SoCalGas submits that the Energy Division should follow Rule 23 regarding curtailments and specify the level of gas curtailment by each zone. Attaching all power plants to a "single gas source and settling total gas delivery limits" based on the hydraulic results does not accurately reflect the curtailment impacts. Furthermore, there is no mechanism which requires gas being delivered to customers that are curtailed to continue flowing into SoCalGas. It is likely that once a customer is curtailed, supplies otherwise being delivered to it would be diverted to off-system customers which would also be subject to stressful market conditions. In fact, the receipt point utilization assumptions may be overly optimistic because reliable gas deliveries are highly related to gas transported using firm contracts on the interstate pipelines, which are not required to be held by any customers other than retail core customers.

Next, Energy Division states that it will re-run the "As Found" case and identify the changes in Loss of Load Expectation ("LOLE") and total production costs when unit dispatch is altered. In this context, SoCalGas recommends a broader analysis to examine the unit dispatch of generators outside of the 17 power plants and those that are outside of the Southern California system that would also have significant constraints given the peak winter day conditions and supply availability on the SoCalGas system and other systems. These more distant power plants could still have reliability or cost impacts in such circumstances that need to be considered.

Finally, SoCalGas recommends that Energy Division clarify how SERVM and the hydraulic modeling will be integrated, and, in addition, Energy Division should clarify how the hydraulic modeling constraints and/or potential curtailments to in-basin gas generators will be incorporated in the Production Cost Modeling. Criteria should be provided to determine if the subsequent modeling results are reasonable.

V. COMMENTS TO THE ECONOMIC MODELING IN THE UPDATED PROPOSAL

a. General Comments

As a threshold matter, the additional costs to firm up supplies to meet core customers' design day needs in lieu of Aliso Canyon are not mentioned as part of the economic modeling effort. Without Aliso Canyon, SoCalGas does not have sufficient firm supply sources to meet its obligations to customers under design day conditions. SoCalGas would need to secure alternative firm supplies either in the form of long-haul pipeline capacity or LNG supplies, and invest in additional pipeline infrastructure, all of which results in additional costs.

Seasonal gas cost differentials are not accounted for in the Updated Proposal. Aliso Canyon allows SoCalGas' customers to purchase gas supplies in the lower priced non-peak season to use during a higher priced winter season to reduce their overall gas costs. Energy Division should conduct a separate analysis that examines the benefits of capturing seasonal spreads for customers, from purchasing in the daily, or monthly market during the summer and withdrawing during the winter. As proposed, the volatility analysis will not be able to capture seasonal spread cost impacts.

The proposed economic analysis should be based on forward-looking market conditions corresponding to the near, mid, and long-term assessment periods. SoCalGas recommends using a gas market fundamental model to project future gas prices. Similarly, another potential approach would be to examine historical NYMEX and forward bases to determine the relationship of forward seasonal prices with key market fundamental drivers and project those trends forward.

The model in the Updated Proposal does not appear to account for direct and indirect impacts on electricity prices associated with the interruption or lack of availability of Aliso Canyon. The model appears only focused on Southern California electricity impacts. Electricity demand outside of Southern California (e.g., Northern California, Western United States) impacts both gas and electricity availability. If there are power plant disruptions/maintenances outside of California, such events can impact gas and electricity availability. The model should account for impacts on gas and electricity beyond Southern California, such as Northern California and the Western United States, because any interruption or lack of availability of Aliso Canyon will affect gas and electricity pricing to the extent such needs for gas and electricity need to be satisfied by going beyond Southern California. Even an increase in *concern* over possible interruptions will have upward pressure on gas and electricity pricing.

In this regard, natural gas storage, including specifically, Aliso Canyon, is an integral part of the Southern California system. As stated above, storage affects gas and power prices throughout the United States. In addition, storage reduces investment needed for pipeline infrastructure. Storage – and Aliso Canyon – helps keep gas commodity costs down. For example, during the period of limited Aliso Canyon withdrawals and injections, border to City-Gate price spread increased. From November 2015 through middle of June 2018, first month of index spreads have been as high as $3.02, and daily index price spreads have been as high as $15.42. Published daily prices are for gas traded to flow beginning on cycle 1, and gas traded for later delivery cycles has been observed to be much higher during periods of market stress, but are not published.

Furthermore, and as SoCalGas explained in its Comments to the Initial Proposal, economic impacts are not limited to gas and electricity. Higher gas and electricity prices will reduce economic activity in Southern California because there will be some transfer effects to the extent business moves away from Southern California, including reduced revenues in the form of taxes to state and municipal government. For instance, if natural gas prices go up, paying for that increased commodity price takes otherwise disposable income money away from California consumers, and, obviously, reduces economic activity in California. This will impact consumers and state and local treasuries and is a risk that should be identified in the model. “Reasonable cost” is not limited to just the cost of electricity and gas but all economic cost impacts in any given scenario. An example would be the economic losses should a disruption in electric supply occur do to not having Aliso Canyon available. These are the types of impacts that need to be evaluated as deciding today on reducing or eliminating the use of Aliso Canyon will have a permanent impact on its future availability.

Moreover, the Economic Model does not appear to capture impact that removal of Aliso Canyon would have on the average price of gas, which is distinct from volatility and downstream impacts on electric generation ("EG") prices. Withdrawals from Aliso Canyon are an additional source of supply that compete with other sources. Hence, taking Aliso Canyon out of the market will in effect reduce supply competition and increase prices.

The Updated Proposal also does not lay out economic cost associated with decreased reliability (e.g., impact of curtailments and brownouts). Such events have direct and indirect economic costs associated with them and should be addressed and quantified in the scenarios and are risks that should be identified in the model.

The Energy Division should also clarify how it intends to incorporate the results of the gas price volatility model into the Economic Model and explain the relationship between the volatility model and electric and gas cost outputs.

The Updated Proposal proposes to evaluate the impact on EG heat rate by conducting implied market heat rate analysis, with and without Aliso Canyon, based on historical heat rates for 2015, 2016, 2017.[34] SoCalGas submits that this methodology may not accurately capture the impacts due to the relatively mild winters over that period. Rather, Energy Division should evaluate it prospectively with forecast conditions based on a longer historical sample.

Finally, in addition to modeling the proposed inventory levels, SoCalGas recommends including a scenario where Aliso Canyon is opened to the inventory level (and corresponding withdrawal rate) consistent with its maximum allowable operating pressure for each of the years modeled. This model will help provide a bookend or reference point for the economic impact that will occur if Aliso Canyon is restricted.

b. Specific Comments

i) Comments on Volatility Analysis

Energy Division states that it will perform historical analysis on daily and monthly analysis of the SoCalGas City-gate hub, and compare that to other upstream and downstream gas points.[35] As proposed, this analysis does not capture Aliso Canyon's cost savings from seasonal price differentials. A separate analysis is needed as discussed above. The proposed analysis could most likely only capture the impact of more frequent and extreme price spikes in the daily market.

In addition, Energy Division should clarify what methodology will be used to determine the potential impact of higher volatility on consumer gas costs. Additional steps/analyses are

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[34] *Id*. at pp. 28-29.
[35] *Id*. at pp. 25-26.

needed beyond the econometric volatility model currently proposed. Indeed, higher gas price volatility will also have impacts on electric prices. Spiking gas prices will lead to much higher electric prices as gas generators are most likely on the margin. A complete volatility analysis should examine the impacts on both gas and electric prices.

ii) Comments on Factors That Mitigate Natural Gas Storage

Energy Division states that it will examine the factors influencing the storage injection and withdrawal decisions using a linear time series, with key explanatory variables including weather, price, OFO, days of the week and inventory level.[36]

Here, Energy Division should clarify the purpose of this proposed analysis and further explain how this analysis will be conducted. As currently stated, the proposed analysis is not directly linked to the primary objectives of the scenarios being developed.

iii) Comments on Impact of Natural Gas Storage on Ratepayers

For this portion of the scenarios, Energy Division proposes to conduct a historical "Difference in Differences" ("DID") study to quantify the effect of storage availability on ratepayers. The study will examine the bills of SoCal and PG&E customers prior to October 2015 and after to estimate the effect of curtailment of the Aliso Canyon facility on monthly gas bill.

This analysis, however, is too narrow to provide insights on whether the period in which Aliso Canyon had a temporary moratorium on injection has increased customer bills. Customer gas bills, by design, are relatively stable over time and may not reflect the most recent market or gas system operating conditions.

In addition, the analysis as proposed should incorporate controls for certain factors to isolate the impact of storage on customers' bills. For example, for PG&E, the total rates increased from $1.07/therm in Oct 2015 to $1.32/therm in October 2016, and most of this increase was largely due to the non-gas supply portion, which is not impacted by storage inventory. Consideration should also be given to any future impacts from PG&E's proposed reduction in utility-owned storage.

SoCalGas submits that an alternative framework to examine future consumer bill impacts should be utilized, which includes estimating economic impacts on different classes of natural gas customers and aggregating to derive annual cost of service increase and customer bill impact based on standard rate assumptions. Aliso Canyon's economic impact to gas customers' cost of service could include: upstream transportation charges to replace Aliso Canyon deliverability for core customers, seasonal spreads/intrinsic storage benefits, volatility impact on gas and electric prices, and OFO/balancing impacts on gas prices.

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[36] *Id*. at p. 26.

iv) Comments to the Implied Heat Rate and Congestion Rent Analysis

Energy Division proposes to analyze the historical impact of moving generation outside of LA Basin by conducting analysis on implied heat rate and congestion rent analysis for 2015, 2016 and 2017.[37]

Here, SoCalGas submits that proposed historical analysis will be impacted by weather and other factors which may not properly reflect the future electric market conditions. The impact on the costs faced by electric consumers is better reflected by future wholesale market price projected with and without Aliso Canyon. Furthermore, Aliso Canyon, through its impacts on the natural gas market price, will affect electric wholesale price both in Northern California and other WECC regions. In this context, and as stated in SoCalGas' Comments to the Initial Proposal, SoCalGas recommends using a model that is capable of projecting electricity prices with and without Aliso Canyon, such as PLEXOS, in order to capture Aliso Canyon's impact to electric consumers.

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SoCalGas appreciates the opportunity to submit comments to the Updated Proposal and the Commission's consideration of the issues identified in this letter and at the workshops in this proceeding. In addition, holding hearings on these assumptions is the only way the consumers in California can be assured that the results of the proceeding will produce reasonable results and ensure their energy reliability is being appropriately addressed.

Sincerely,

/s/ Sabina Clorfeine
Sabina Clorfeine
Assistant General Counsel
SOUTHERN CALIFORNIA GAS COMPANY

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[37] *Id*. at pp. 27-29.

EXHIBIT A

Southern California Gas Company's Response to Update to the Scenarios Framework (Investigation 17-02-002)

Western Interconnection Gas – Electric Interface Study

Public Report

JUNE, 2018

Contents

1. Introduction

Executive Summary

The Western Interconnection is currently undergoing a fundamental transformation with the retirements of baseload resources and large additions of solar and wind generation. Up until 2015, Aliso Canyon's 86 bcf of market-area gas storage and 1.8 bcfd of withdrawal capacity were historically sufficient to balance system variability in the Southern California region. However, the operational limitations[1] imposed on Aliso Canyon are now highlighting several issues that were previously masked; we are now effectively in an N-1[2] scenario with any major disruptions in the gas transmission system or the Bulk Power System (BPS) pushing the system to the limit.

We expect two major factors to transform the role of natural gas generation in the electric power system of the Western Interconnection as we move forward:

- System reserve margins are expected to become increasingly tight through 2026, driven by baseload coal and nuclear retirements as well as steady increases in power demand; as a result, Wood Mackenzie and E3 forecast natural gas demand for power generation across the Western Interconnection to increase by 30% by 2026.
- Expansion of low-cost renewable generation capacity driven largely by state renewable policy goals will limit the overall need for utilization and dispatch of natural gas generation but will not fully replace the need for dependable electric generation capacity to meet peak demands and ensure the reliability of the bulk power system (BPS); while some of the capacity needs may be met by energy storage added in conjunction with increasing renewable penetration, the need for firm generation will not be eliminated.

To explore the nature of the vulnerability of electric reliability to major gas infrastructure disruptions, we examine multiple disruption scenarios representing pipeline ruptures, compressor station failures, and supply freeze-offs. Modelling and analysis of multiple disruption scenarios yields a number of key findings:

- The configuration of the gas-electric system combined with the retirement of Aliso Canyon creates region-wide reliability issues, resulting in widespread loss of electric load; the Southwest and Southern California regions appear to be most vulnerable to major disruption events due to 1) heavy reliance on gas generation to meet peak demands, and 2) limited gas storage capability.
- Other regions in the Western Interconnection are more resilient to major gas system disruptions, largely owing to increased compensation capabilities stemming from market-area gas storage and alternative energy sources including reliance on the region's robust interstate transmission system
- The existing strain on the system indicates that even modest changes to working assumptions such as fossil fuel plant closures or natural gas storage limits could exacerbate existing challenges; natural gas support will continue to be necessary to ensure system reliability while achieving policy goals.

Consequently, the development of a balanced portfolio of mitigation options is critical to assure system reliability in a changing power landscape. Maintenance of and new investments in gas and electric infrastructure are necessary to preserve reliability of the BPS:

- Maintaining and investing in natural gas infrastructure — including supply, delivery, storage, and generation—is necessary to meet the near-term and long-term reliability needs of the Western Interconnection even as the BPS transitions towards higher penetrations of renewable and energy storage resources.
- At the same time, pursuing a balanced portfolio of alternative mitigation strategies can help insulate the BPS from reliability risks at the gas-electric interface; these include investments in renewable generation and energy storage, demand response programs, and dual-fueled generation capability.

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[1] Working capacity reduced to 24 bcf

[2] Refers to a contingency involving the unexpected failure or outage of a system component. N-1 refers to the failure of one large system component, N-2 refers to the combination of two such failures, etc.

- Improved coordination of gas and electric industries' operating practices will be critical for maximizing compensation capability and ability to respond to both business-as-usual and sustained disruption scenarios. The project team has identified five distinct areas for potential change:
  - **Improved Regional Coordination**: Implementation of regional contingency planning exercises led by WECC to facilitate coordination and compensation responses
  - **Resource Adequacy Assessment**: Greater transparency of firm gas supply contracting and linkage to power plants served in planning reserve margin reports to allow for more robust planning processes
  - **Curtailment Priorities**:1) Designation of specific plants as critical to grid reliability as core end-use to allow for additional flexibility for compensation via transmission, 2) Additional clarity around interstate pipeline curtailment protocol (e.g. transparency around single-sourced customers and other possible exceptions to written protocols)
  - **Forecasting & Execution**: Revisit LDC balancing procedures for core customers (e.g. previous-day nominations versus actual usage) to alleviate operating pressures on generation customers
  - **Gas-Electric Day Mismatch**: Split of the existing weekend nomination period into daily blocks, resulting in a 7-day nomination cycle to minimize response times over the weekend period
- Moving these changes forward will require buy-in at all levels (e.g. gas pipeline operators, utilities, generators, PUCs, NERC, FERC) in order to effectively improve existing protocols and procedures

Background

In September 2017, the Western Electricity Coordinating Council ("WECC") commissioned Wood Mackenzie ("Woodmac"), Energy + Environmental Economics ("E3"), and Argonne National Laboratory ("Argonne") to conduct a study of the gas-electric interface in the Western Interconnection to identify potential threats to grid reliability at present and in the future. The Western bulk power system ("BPS"), which includes a regionally and technologically diverse portfolio of generation resources, is currently undergoing two simultaneous major transitions that will impact its future operations and the role of natural gas generation:

- Baseload coal and nuclear plants are expected to retire in significant quantities in the coming decade
- Cost reductions and regional policies will result in significant deployment of low-cost variable resources such as wind and solar PV

Each of these changes will impact the role of natural gas generation in the power system, though their impacts will be different (and in some instances, countervailing). Retirement of existing baseload resources will most likely result in increased commitment and dispatch of existing natural gas generation and may require additions of new firm gas generation capacity to ensure system reliability. The addition of renewable generation, on the other hand, will tend to reduce dispatch of gas generators for supplying energy, but will not fully displace the need for dispatchable resources to ensure system reliability due to the variability and intermittency of solar and wind resources. While the net impact of these two transitions on the overall level of gas throughput will depend on the pace of each transition, a large base of installed natural gas capacity will undoubtedly continue to play a crucial long-term role in meeting the reliability needs of the Western Interconnection, providing key flexibility and peaking services to the BPS.

As the BPS undergoes major changes in the composition of its resource base, the ability of the gas delivery network of the Western Interconnection to keep up with increasing peak demand becomes a key question. The challenges faced in the Los Angeles Basin because of the Aliso Canyon gas storage field situation in 2015 have focused attention on the reliability and adequacy of the existing natural gas delivery system to support electric generation in the West now and into the future.

The project team of Woodmac, E3, and Argonne was selected for their combined ability to bring a detailed and comprehensive view of both the gas and electric industries as well as their ability to provide granular modeling capabilities, which was critical to the success of this study:

- Wood Mackenzie is a commercial research and consulting firm whose expertise spans the entire energy value chain. Within the natural gas industry, Woodmac leverages its world-class research capabilities and expertise to form a comprehensive view of gas markets, supported by its detailed upstream and production data, demand forecasts, and midstream flow/price modeling capabilities
- E3 is one of the premier power consulting firms in the West and possesses extensive experience in all sectors of the electricity industry. E3 provides unparalleled expertise of power markets, planning, policy, regulation,

economics, and environmental concerns, underpinned by their granular and detailed models of both present and forecasted power mix
- Argonne National Laboratory is a US Department of Energy (USDOE) multidisciplinary science and engineering research laboratory with significant experience in disaster impact analysis and pipeline hydraulic modeling. Argonne has substantial experience in similar reliability studies and consequently can leverage its comprehensive datasets on power plants, gas pipelines, and gas contracting

To this end, the project team engaged in an extensive eight-month effort with input from key gas and electric stakeholders to 1) conduct an assessment of market dynamics through 2026; 2) define and model 10 natural gas disruption scenarios and evaluate the resulting impacts to the BPS and 3) analyze the capabilities and cost of potential mitigation options and identify actionable recommendations for improving existing operations, procedures, and protocols. Ultimately, the goal in the study was to identify where and under what conditions fuel supply risks exist and to identify possible mitigation options for utilities to ensure that the gas generation fleet has a reliable supply of fuel that can allow for the flexible generation profiles we expect to become increasingly prevalent in the future.

This Public Report details the key findings and results from our study, which utilizes the 2026 WECC Common Case[3] as its base forecast. While this study incorporates and utilizes significant input provided by key utilities and gas pipeline operators in the West, the statements and opinions expressed in this document reflect the views held by the project team of Woodmac, E3, and Argonne. This document is intended for public circulation and consequently does not include all supporting details and information from the study due to confidentiality reasons.

2. Western Interconnection Market Dynamics

The BPS of the Western Interconnection has historically been powered by a diverse mix of energy supply resources and associated delivery infrastructure:

- Baseload coal and nuclear generation,
- Baseload, intermediate, and peaking natural gas generation, supplied by long-haul gas pipelines and market-area storage,
- Large-scale hydroelectric generation, and
- Variable and baseload renewables generation (e.g. solar, wind, and geothermal)

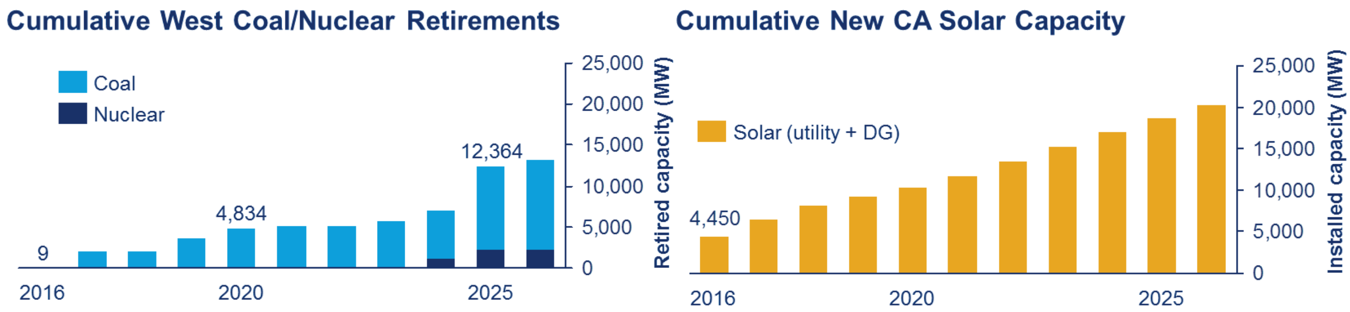
Historically, the existing network of interstate and intrastate gas pipelines and storage facilities have been sufficient to meet the operating needs of gas generators in the BPS. However, the gas-electric system has already experienced a number of events symptomatic of a system operating at or near its physical limits:

- Unplanned SoCalGas pipeline outages in fall 2017 resulted in gas price spikes of >$12/mmbtu,
- Freeze-offs in winter 2018 brought the interstate gas system to the brink of firm gas curtailments, and
- In March 2018, the CPUC ordered SoCalGas to inject gas after storage inventories reached “critically low” level

The gas-electric interface of the Western Interconnection faces increasing volumetric and flexibility constraints that could translate to reliability challenges. Coal and nuclear retirements create a deficit of baseload generation capacity in the bulk power system, increasing the dependence on gas. Large additions of renewables help mitigate the loss of coal- and nuclear-generated power but do not replace the increased need for the firm, dependable capacity provided by natural gas generation.

[3] 2026 WECC Common Case version 1.5

Figure 2.1: Cumulative Baseload Coal and Nuclear Retirements in the Western Interconnection and Cumulative California Solar Capacity



This study uses the WECC 2026 Common Case[4] as the basis of the analysis conducted. The Common Case, using assumptions developed from current utility plans and state energy policy, assumes the following key changes to the loads and resources of the Western Interconnection:

- Retirements of ~9 GW of coal and ~2 GW of nuclear by 2026 across the region, including major baseload plants in California, the Pacific Northwest, and the Desert Southwest
- Wind capacity increases by 9 GW to reach 29 GW of capacity, with the majority of additions in the Pacific Northwest
- Solar capacity doubles to 36 GW of capacity by 2026, with 18 GW of additions solely in California
- Total Western Interconnection load increases by ~7% from 2018 to 2026

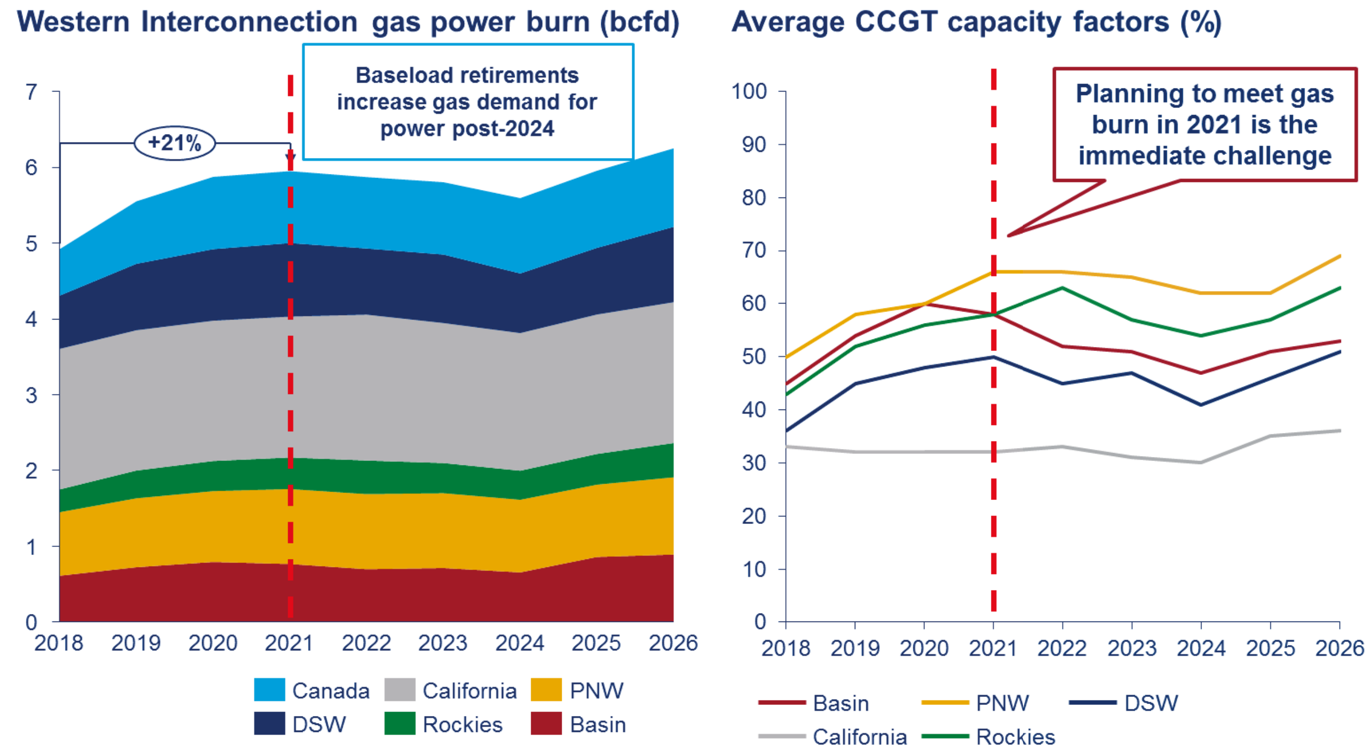
The changing composition of the generation fleet in the Western Interconnection has several implications for the role of natural gas within the electricity sector.

First, at the levels of baseload retirements and renewable additions considered in this study, overall reliance on natural gas for electricity generation will increase in the coming decade. The amount of renewable generation needed to meet current state policy goals is not sufficient to entirely offset the loss of roughly 12,000 MW of baseload generation retirements. Figure 2.2 shows the trend in natural gas demand and utilization of combined cycle gas turbines between 2018 and 2026; across the full Western Interconnection both trend upward, linked directly to the scheduled retirements of baseload generators shown in Figure 2.1. Specific trends vary by region; for instance:

- In California, where addition of renewables to meet a 50% RPS policy goal is expected to drive large and steady investment in renewables, gas utilization declines slowly until 2024, when the retirement of the 2,000 MW Diablo Canyon Nuclear Power Plant causes a notable upward swing in gas dispatch.
- In the Southwest and Northwest regions, coal plant retirements planned for the coming years are expected to result in a near-term increase in demand for natural gas generation; if additional coal plants are shut down this upward trend could be exacerbated. Our market analysis has been supported by additional discussions with key pipeline operators in the region, who have all expressed concerns around tightening constraints and less available capacity in the same timeframe.

[4] WECC 2026 Common Case version 1.5

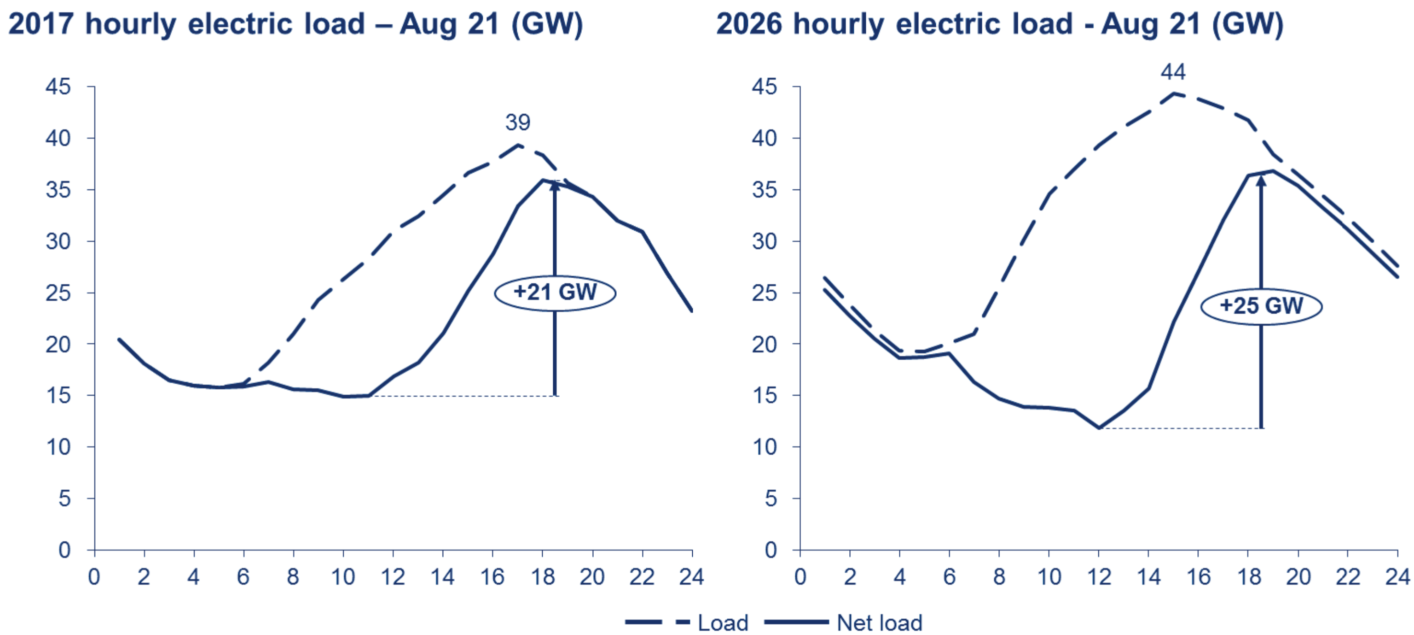
Figure 2.2: Forecast of natural gas demand for power generation and CCGT capacity factors



Second, natural gas generation will play an increasingly important role in meeting system reliability needs during peak periods. Because of their timing of production and intermittency, wind and solar PV resources have a limited contribution to meeting regional peak demands compared to firm, dispatchable resources like coal or natural gas. While energy storage appears poised for a major cost breakthrough, its capability to displace the need for firm generation resources is currently unknown but likely limited; the need for energy storage resources to maintain a state of charge to dispatch on demand and their reliance on other generation resources to provide that state of charge limits their potential contributions to system reliability. As a result, natural gas resources will continue to play a growing role in meeting regional capacity needs, and with the retirement of significant quantities of firm baseload generation, additional investment in gas generation is likely needed within the region to meet reliability needs.

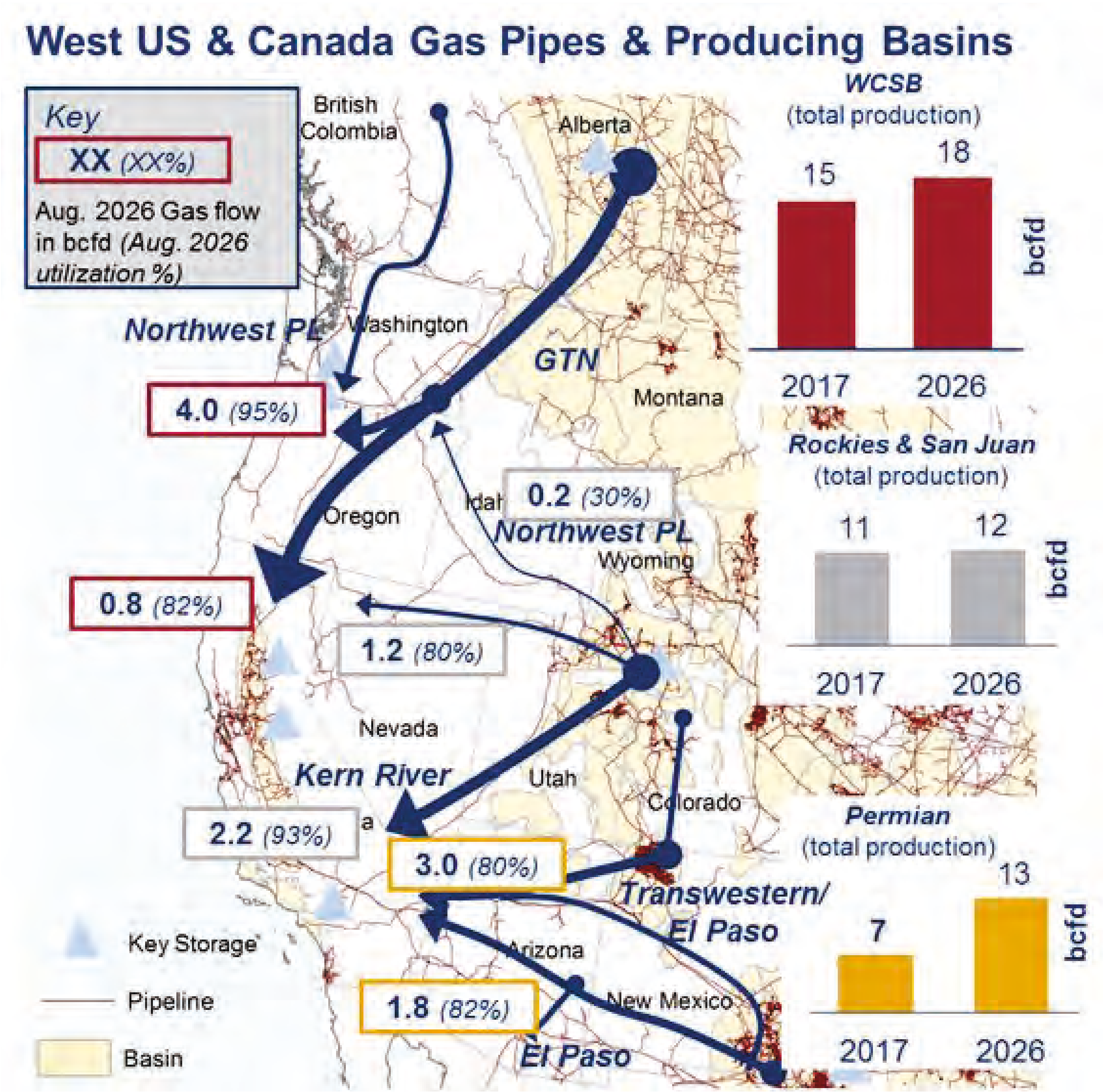
Third, the changes in the resource mix of the Western Interconnection will change the timing and nature of how gas generation resources are dispatched and, by extension, the patterns of demand for natural gas. Increasing penetrations of intermittent renewable generation—specifically, wind and solar PV—will lead to increasingly variable and uncertain “net load”—electricity demand less the output from renewable resources. This phenomenon is illustrated in Figure 2.3, which shows the change in California net load between 2017 and 2026 on a typical summer day. The anticipated expansion of solar PV in California creates a need for significant upward ramping capability over a relatively short times scale (approximately three hours); much of this upward ramping capability will be met by flexible natural gas generation. In an industry whose business practices and conventions are largely designed around the concept of a ratable gas day, the increasingly variable and uncertain nature of natural gas demand may creates strains between pipelines and generators.

Figure 2.3: Forecast of natural gas demand for power generation and CCGT capacity factors Comparison of 2017 and 2026 Hourly Electric Load in California



Of course, the impacts described above are an outcome resulting from the specific assumptions made in the study with respect to baseload retirements and renewable additions. Events that have occurred since the time of the development of the Common Case appear likely to accelerate the trends discussed above; utilities have announced plans to shut down additional coal units, and advancing policy discussions in many states and demand for clean energy resources increasingly driven by customer demands may also lead to increased renewables and energy storage over this same time period. These uncertainties make the outlook on natural gas demand in the power sector itself uncertain in the future; however, regardless of the level of natural gas demand in electricity, natural gas generation will continue to play a crucial role in meeting the region's reliability needs, and maintenance (or even expansion) of infrastructure needed to ensure its availability cannot be neglected.

Figure 2.4: Western US & Canada Major Natural Gas Pipelines and Gas Basins



The Western Interconnection enjoys access to diverse, abundant, and economic natural gas supply sources between the Western Canada (WCSB), Permian, Rockies and San Juan basins. The combined reserves represent 350 tcf available at break-evens of less than $4/mmbtu for dry gas and $50/bbl for associated gas. However, this wealth of resources is dependent on a limited number of long-haul pipelines to deliver natural gas from supply areas to large demand centers in the Pacific Northwest, California and the Desert Southwest:

- DSW markets (e.g. Phoenix) are essentially dependent on the El Paso and Transwestern pipelines
- PNW markets rely upon Northwest and GTN pipelines for their natural gas as well as gas storage
- Northern California markets are supplied by GTN and, to a lesser extent, Ruby pipelines as well as gas storage
- Southern California markets are reliant on El Paso, Transwestern and Kern River pipelines as well as gas storage

This widespread reliance on long-haul pipelines results in reliability risk due to the potential for disruptions in delivery capability; a major gas disruption at a single point can have additional effects in several different markets.

As shown in Figure 2.4, most major interstate pipelines in the West are expected to be highly utilized (80% - 95% on peak month basis, of which about half of the demand comes from power generation). Natural gas supply to the Desert Southwest will become increasingly supplied from the Permian basin, as San Juan production is expected to slowly decline over time. This switch will create a greater reliance on Permian and West Canadian gas for the West region, with potential reliability risks in Desert Southwest and Southern California, as well as the Pacific Northwest that are studied in the next section.

Another critical assumption to this study is the decommissioning of the Aliso Canyon underground natural gas storage. This assumption was made in order to examine the full impact of disruptions of the gas infrastructure without the presence of any major gas storage in Southern California. The study considered sensitivities to this scenario, which are presented in the following sections: a scenario with Aliso Canyon remaining online at the reduced operational capacity and a scenario with an underground gas storage facility in Arizona, to assess the impact of these facilities on the disruptions modeled.

From the market analysis, several critical factors become apparent:

- Gas burn is expected to increase significantly, driven by baseload coal and nuclear retirements as well as overall load growth in the region. While additional renewables capacity provides some mitigation, the study results presented in the next section show that it will not be enough to offset the 11 GW of retirements and will also introduce additional volatility and uncertainty into intra-day swings
- Maintenance, and possibly expansion, of gas system infrastructure will likely be needed to meet reliability needs
- The Western Interconnection has access to ample supply from several different supply basins, but its reliance on long-haul gas pipelines poses reliability risk due to the ability of a single disruption to impact multiple markets

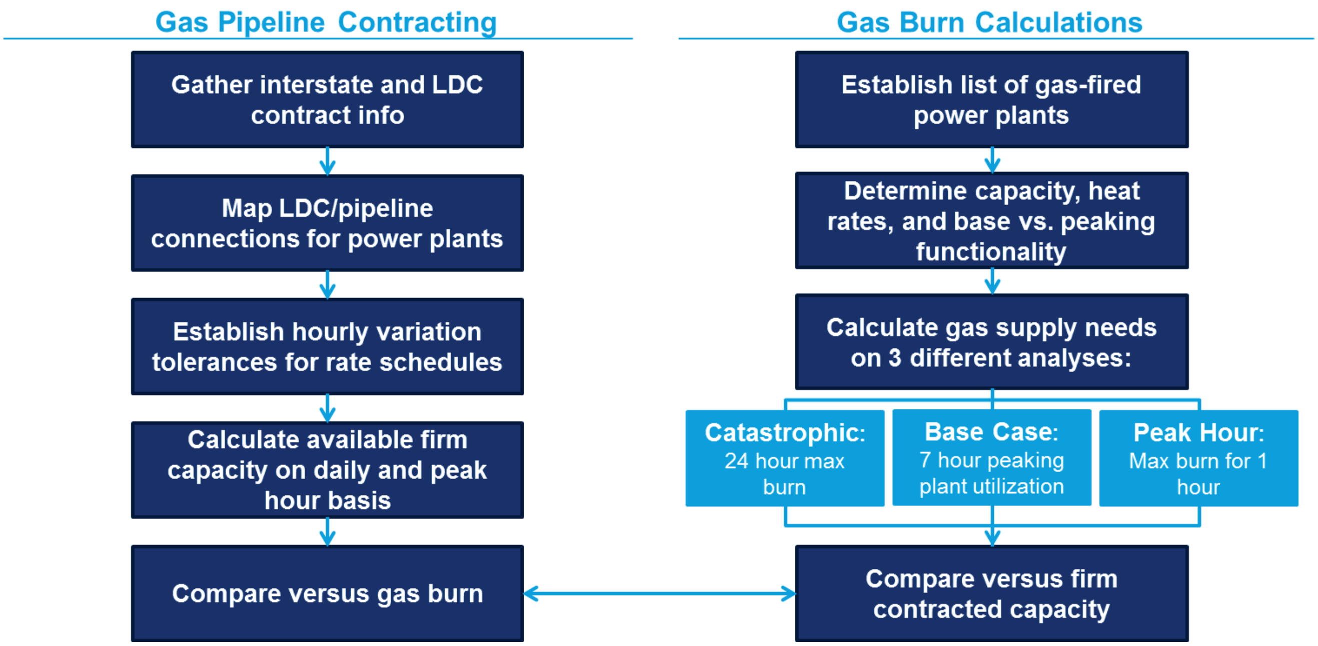
3. Modeling Scenario Analysis & Results

The modeling efforts in this study formed one of the key components for the entire project by providing a reasonable estimate of the potential impacts that could result from each of the disruption scenarios. Consequently, there were several aspects that had to be pulled together to accomplish this complex analysis:

- **Contracting Analysis**: An analysis of all gas contracting positions in the Western Interconnection was undertaken to further refine the inputs to the modeling setup, as this plays a key role in how plants are supplied and which power plants are ultimately affected during shortages and/or curtailments.
- **Modeling Setup**: Coordination among the three major models (AURORA, NGfast, GPCM®) was necessary to set up the Base Case using the 2026 WECC Common Case and establish a robust process for modeling each of the disruption scenarios.
- **Modeling Results Validation**: Multiple iterations were conducted for each disruption scenario to validate the modeling results and ensure that gas-side and electric-side compensation (from line pack, storage, transmission, etc.) was accurately reflected.
- **Probabilistic & Economic Analysis Impact**: Translation of the unserved energy and unmet spinning reserves into "unrisked" and "risked" economic impact served to provide context for the magnitude of each disruption scenario.

Contracting Analysis

Figure 3.1: Contracting Analysis Methodology



A key component of the modeling efforts was the contracting analysis work stream, in which the project team analyzed the contracting positions for each utility and generator in the Western Interconnection to gain a better understanding of how much of their plant capacity was covered by firm transport (FT) contracts. As shown in Figure 3.1, the contracting analysis was conducted on three different bases:

- **Catastrophic**: a 24-hour max burn of baseload and peaking plants to simulate a sustained disruption stemming from a catastrophic event
- **Base Case**: a 7-hour peaking plant utilization to simulate business-as-usual conditions (as used in several IRP processes)
- **Peak Hour**: a 1-hour max burn to analyze peak-hour demand versus available peaking services offered by pipeline operators

The project team estimated to the gas burn needed under all three bases by using the plant capacities, heat rates, and associated base vs. peaking functionality of each power plant. These figures and results were validated with the key utilities and generators throughout the Western Interconnection on a best-efforts basis.

The gas burn needs were compared against the firm contracting position for each utility and generator in the Western Interconnection. The project team reviewed online contracting info, pipeline indexes of customers, IRPs, marketing agreements, and validated results through contact and communication with the various utilities and generators to form an accurate picture. Combining these two analyses allowed the project team to form a view of how much generation capacity was uncovered by FT contracting in each of the three bases.

This contracting analysis was also instrumental in updating the proprietary dataset used in modelling disruption impacts to gas-fired power plants and formed a critical part of our modeling analysis by allowing for a more accurate simulation of curtailment procedures of firm versus interruptible gas supply.

Figure 3.2: Contracting Analysis by Region for Gas-fired Generation Capacity

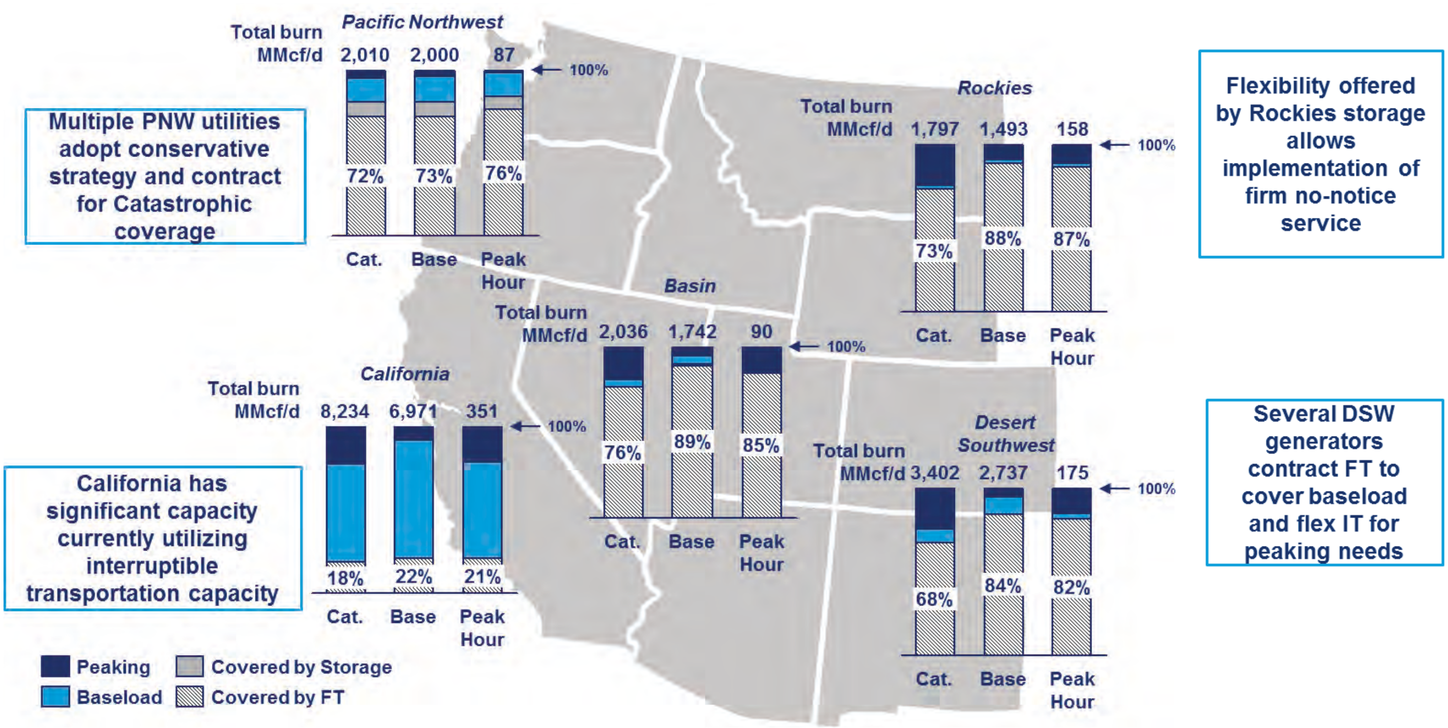


Figure 3.2 shows a regional breakdown for the contracting analysis across the Western Interconnection, using the aforementioned three bases for calculation. Outside of California, approximately 10% – 20% of gas-fired generation is not covered by FT[5] contracting; Pacific Northwest (PNW) and Rockies utilities have typically adopted a more conservative strategy with several companies having contracted for full coverage even on the 24-hour max burn basis. However, this is feasible due to the flexibility offered by gas storage, which allows the implementation of firm no-notice service for utilities and generators. Within the Desert Southwest (DSW) where storage options are nonexistent, utilities and generators were typically more reliant on IT[6], especially for peaking generation; in this particular region peak demand for gas generation occurs during the summer which is off-season for overall peak gas demand, which has contributed to utilities historically feeling less need to contract for FT.

The situation in California is considerably different from the rest of the region:

- Virtually all generation on the local LDC system is effectively unsupported by FT due to existing curtailment protocols; consequently, ~80% of capacity is essentially relying on IT-type contracting for >23 GW of gas-fired generation.
- The California intrastate systems are designed to be capable of meeting all demand (both core and non-core) under a 1-in-10 year cold weather event (though, with the reduced capability of Aliso Canyon, the current system may not meet these design criteria), but curtailment protocols classify electric generation as non-core end-use, meaning that utilities and generators would be the first to be impacted during curtailments.

The difficulties resulting from such a setup were previously avoided by the flexible capability of Aliso Canyon; the loss of this facility may now impede utilities' ability to operate effectively on a day-to-day basis. Additionally, because generators are considered non-core customers, there is little value in holding FT further upstream on interstate pipelines feeding into California. As a result, generators have already released or expressed intentions to release firm capacity from several pipeline systems. This lack of alignment of commercial incentives also makes it more challenging for pipeline operators to

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[5] Firm Transportation contracts ensure pipeline capacity on a firm basis and is generally not subject to reduction or interruption

[6] Interruptible Transportation contracts are subject to curtailment or interruption due to operating conditions or pipeline capacity constraints

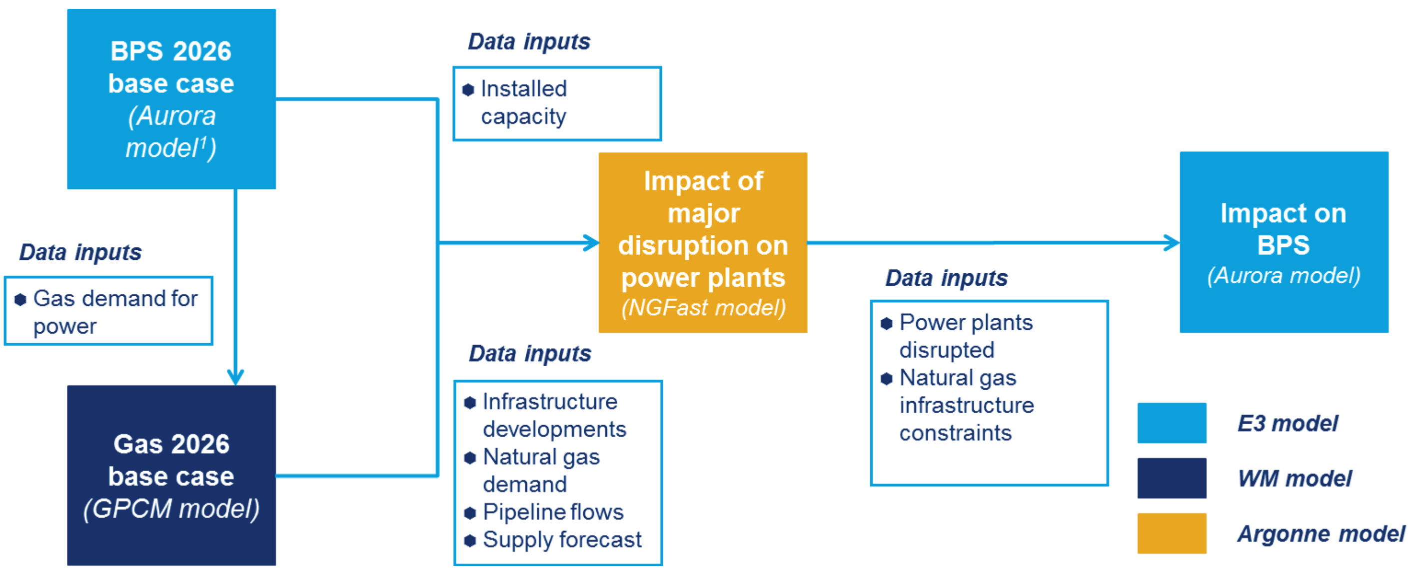
secure enough interest during open seasons for new expansion projects on their systems. These disincentives create significant long-term reliability concerns as it ultimately reduces the ability of pipeline operators to invest in their system to increase reliability and deliverability for power generators.

The contracting analysis undertaken in the study yields a few key conclusions:

- Although behavior varies from company to company, a common contracting approach is to contract enough FT capacity to cover baseload needs and flex on IT capacity for peaking generation. While this practice is feasible for systems with ample spare capacity or dual-fuel generation, this will become more difficult as gas market dynamics tighten across the West
- There is currently limited transparency and visibility into how gas-fired generation is supplied on a contracting basis; it is unclear how gas contracts are linked to the specific plant(s) they serve, which makes contingency planning difficult. Existing processes cover resource adequacy analysis but do not engage in contingency planning exercises
- The issues resulting from existing LDC curtailment regulations in California are becoming more apparent with reduced Aliso Canyon operations, and multiple utilities and generators have indicated the increased operational difficulties stemming from these regulations. With no true FT-type contracting available for generation in California, utilities and generators are more susceptible to curtailments and also have less incentive to hold FT contracts on interstate pipelines leading into California, which is becoming increasingly unsustainable. While holding FT contracting will not enable generators to completely avoid curtailment (e.g. during high-impact, catastrophic disruptions), it does improve reliability for a number of other scenarios by virtue of moving generation further down the curtailment priority list (for interstate pipelines)

Modeling Setup

Figure 3.3: Detailed Modeling Methodology



The project team combined its modeling capabilities to create a robust methodology (Figure 3.3) for modeling each of the disruption scenarios. Three different and well-established models in the industry were used for this study:

- **GPCM®** is a model used in the industry to develop forecasts and scenarios for North American natural gas flows, price and basis. It includes forecasting of pipeline and storage utilization, deliveries and price at points throughout the North American gas market
- **AURORA** by EPIS is a model used in the industry for electricity forecasting and analysis. It produces electric market price forecasts, and automated system optimization
- **NGfast** by Argonne National Labs is a natural gas pipeline network modeling tool that enables the rapid assessment of impacts from disruptions and flow reductions in the nation's natural gas network

Syncing and coordination among three different modeling tools was critical for the study:

- The project team began by developing a base case reflective of the WECC 2026 Common Case using E3's AURORA model on the power side and Wood Mackenzie's GPCM® model on the gas side
- For each disruption scenario, Argonne's NGfast tool was utilized to identify specific power plants impacted and/or suffering outages due to the specific disruption event, with gas compensation taken into account (e.g. gas storage, line pack, etc.)
- Using the list of impacted plants, E3's AURORA model was used to simulate the operations of the electric power system during the disruption event, providing an estimate of the amount of unserved energy and unmet spinning reserves[7] while accounting for the latent capability of the transmission and generation infrastructure to compensate for the disruption.

Scenario Modeling Results

Figure 3.4: Table of Disruption Scenarios[8]

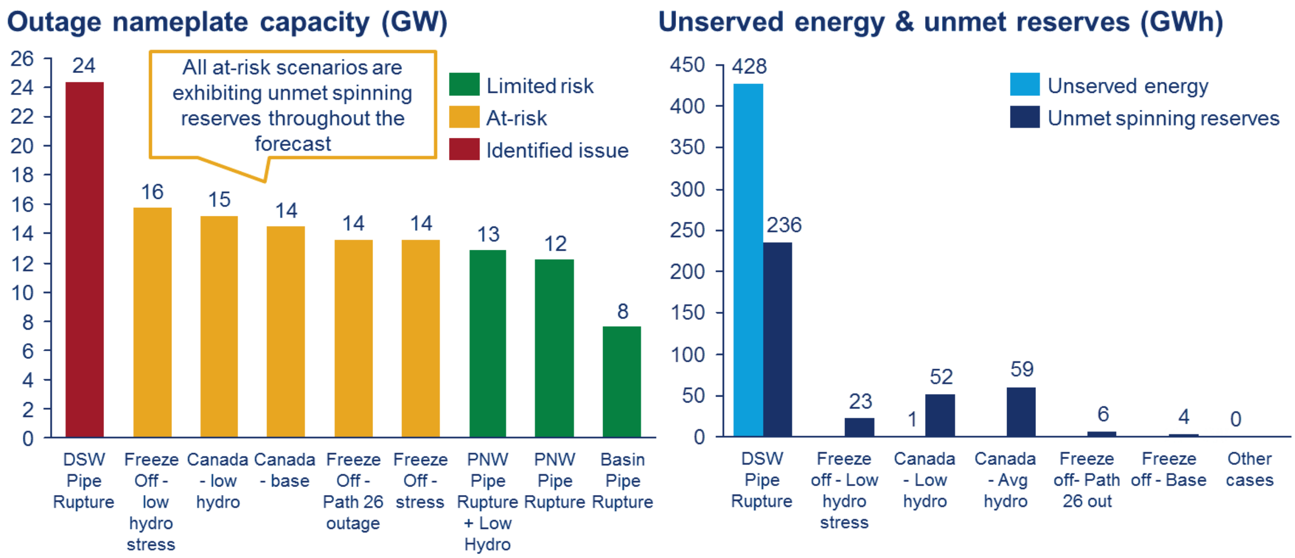
	Regional focus	Base (N-1) Case	N-2 case
Disruption on a PNW pipeline	Pacific Northwest	Disruption at the US/Canada border (or upstream) receipt point on the system	Low hydro conditions
Seismic event disrupting Alberta supply	Pacific Northwest	M6+ earthquake in the Rocky Mountain House area, that disrupts natural gas production in Alberta	Low hydro conditions
Disruption on a Basin pipeline	Basin/ California	Disruption on the critical mainline section downstream of the supply basin and upstream of the demand centers	Low hydro conditions
Disruption on a DSW pipeline	Desert Southwest/ Southern CA	Disruption on critical Southern NM section of DSW pipeline	NA
Winter supply freeze-off in the Permian & San Juan	Desert Southwest	Week-long winter supply freeze-off in the Permian and San Juan basins reducing supply by 1.5 bcfd, higher residential gas demand. 15% of generation in AZ/NM unavailable due to freezing conditions	Low hydro conditions / Transmission outage from CA wildfire

Using the above modeling setup, the project team modelled ten different scenarios, as shown in Figure 3.4 above. These scenarios were defined using input from key players from both the gas and electric industries to include the most pressing concerns and agreed upon with the WECC Project Steering Committee to capture a representative spectrum of circumstances.

[7] In the operational simulation conducted herein, both unserved energy and the failure to meet spinning reserve needs are taken as an indication of a potential reliability event

[8] As seen below in the results, the impacts for the N-1 DSW pipeline disruption scenario were quite significant; consequently, no N-2 scenario was run

Figure 3.5: Outage Nameplate Capacity, Unserved Energy, and Unmet Spinning Reserves from Modeling Scenarios



As shown in Figure 3.5, the cases that exhibit the most impact are all centered around disruptions that affect the DSW and Southern California markets. However, it is important to note the distinction between the DSW pipeline rupture disruption scenario versus the freeze-off scenarios, as the former provokes a resource adequacy issue, while impacts in the latter result from transmission limitations.

The DSW pipeline rupture scenario results in full disruption of gas service to 24 GW of gas generators, which translates into 428 GWh of unserved energy and 236 GWh of unmet spinning reserves. The impact can be traced back to the configuration of the pipeline system which yields two concentrated "islands" of power demand in Phoenix and Southern California; with the loss of a DSW mainline, there is simply not enough capacity remaining to provide the gas needed to compensate.

The various freeze-off scenarios result in conditions in which the electricity system is stretched to its limits and may face reliability challenges. In these scenarios, the failure of the balancing authorities in the Southwest and California to maintain sufficient spinning reserves could potentially translate directly to load shedding; this poses a real issue as even minor additional changes or impacts could yield unserved energy.

The other sub-regions (PNW, Basin, and Northern California) are more resilient to major gas system disruptions, largely owing to the combination of market area gas storage, presence of alternative energy source (e.g. hydro), transmission connectivity which allows for more electric-side compensation, and convention of contracting for firm fuel supplies for capacity resources. To stretch the electric system to its limits in these regions, it is necessary to assume extremely large-scale disruptions due to a catastrophic event knocking out significant supply from Canada. While not outside the realm of possibility, these events have a low probability of occurring.

Probability Analysis & Economic Impact

Figure 3.6: Unrisked & Risked Economic Impact for Modeling Scenarios

$US bn	DSW Pipe Rupture	Freeze-Off + Low Hydro	Freeze-Off	Canada Disruption	Canada Disruption + Low Hydro	Other cases
Unrisked Economic Impact	$27.4	$2.2	$0.6	$3.7	$3.4	$0

Probability of the disruption over a 10-year period	4%	12%	100%	1%	<0%	
Risked Economic Impact	$1.1	$0.27	$0.6	$0.02	$0.002	$0

The project team was able to translate the unserved energy and unmet spinning reserves into an estimated economic impact using previous studies and events to establish a correlation between interruption duration and cost per unit of unserved energy. This analysis was done by demand sector to provide a more granular assessment. Using the separate correlations by sector, the project team also utilized historical sales by state in order to estimate costs in different geographies.

Probability analysis was then conducted on the various scenarios in order to allow for a risked economic impact estimation. Pipeline disruption frequency was calculated using a 20-year US Department of Transportation (DOT) dataset as well as data from the Pipeline and Hazardous Materials Safety Administration (PHMSA), and taking into account three main factors: 1) annual frequency of occurrence of a pipeline break for each company, 2) percent of pipeline breaks with a shutdown period of one month or greater, and 3) probability that a single pipe break leads to a break in an adjoining pipe in the same corridor. Earthquake probabilities were calculated using interpolated seismic hazard values from the Canada National Building Code and associated statistical trends as well as historical records from Natural Resources Canada. Freeze-off probabilities were calculated using historical studies and records from NERC and FERC, while the low hydro conditions for the Pacific Northwest were based on the critical low hydrological conditions observed in 1937, which are commonly used in resource planning exercises in the region.

As shown in Figure 3.6, from a risked economic impact perspective our modeling efforts highlight the DSW pipeline rupture and the freeze-off as the highest-impact scenarios, though for differing reasons. The low probability[9] of the DSW pipeline rupture reflects the strong overall safety record of the pipeline as well as the security from having four separate pipelines, but the high magnitude of the consequences of such a scenario raises the risked impact. Conversely, the freeze-off scenario shows a lower impact but is a high-probability 1-in-10 year event, which also yields a considerable risked economic impact.

The results of the modeling analysis serve to highlight several key points:

- The Southwest and Southern California's reliance on a few long-haul gas pipelines make them especially susceptible to gas system disruptions, especially in the absence of storage provided by Aliso Canyon. Should Aliso Canyon be shut down, this issue will become greatly exacerbated; it is likely that additional natural gas system infrastructure will be needed, even with increased renewables penetration.
- The compensation capability present in PNW illustrates the utility of market-area gas storage and transmission; the project team needed to assume a very low-probability, high impact disruption as shown in the Canada disruption cases in order to elicit any kind of unserved energy or unmet spinning reserves.
- The results clearly point towards two scenarios as the most concerning, though each has very different characteristics. The impact from a loss of a major DSW pipeline is astronomical in cost and consequently still yields a >$1 bn risked economic impact despite the low probability of occurring, illustrating the importance of resource adequacy. Conversely, the freeze-off scenario impact is much lower, but the regularity with which this event occurs yields a risked economic impact of ~$600 million, which highlights the consequences of having insufficient mitigation capabilities.

9 Probabilities used in this study were calculated as described above, though conversations with pipeline operators indicate this probability could potentially be even lower due to the actual physical configuration and locations of the pipeline system

It is important to note that the modeling efforts and scenario results assume perfect procurement, commitment, and dispatch, which is difficult to achieve in a real-world scenario; the impacts resulting from these contingencies are likely understated.

4. Mitigation Options & Recommendations

With multiple scenarios resulting in unserved energy and/or unmet spinning reserves, it is imperative that the key players in the Western Interconnection appropriately plan for such contingencies. Consequently, the project team has focused on two main avenues:

- Providing an array of options to cost-effectively mitigate the impact of various types of gas supply disruptions and durations. We strongly believe that meeting the future needs of the BPS in the Western Interconnection in a reliable manner will require a portfolio of mitigation options
- Improving existing protocols and procedures to maximize the ability of the above portfolio mitigation options to compensate for losses and outages resulting from sustained disruptions. The results from our modeling scenarios assume perfect electric commitment and dispatch, gas procurement, and industry coordination; in a real-world scenario, having the proper processes in place is extremely important for impact mitigation

Within the scope of this study, the project team examined a number of mitigation options through the lens of each of their capabilities as well as their capital cost. While this analysis did not delve into implementation, we believe that this is an area which merits further consideration and analysis, as having the proper market mechanisms and incentives in place will be critical for moving these options forward.

Mitigation Options Analysis

Figure 4.1: Mitigation Option Comparison

Mitigation Option	Est. Incremental Capex	Barriers to Implementation
Aliso Canyon	Limited	Political and regulatory opposition
AZ Gas Storage Project	$372 million	Open season interest
Gas Pipeline Capacity Expansion	$25 – 500 million (for 75 – 300 mmcfd deliverability)	FERC process duration, open season interest
Dual-Fired Generation	Limited	Environmental and political regulations
Electric DR Initiatives	Limited	Limited
Battery Additions	$12 - $18 billion for 15 GW	Cost, recharging needs
Solar Capacity	Unable to compensate DSW pipeline rupture scenario	Daily profile limitations

Within the study, the project team examined seven potential mitigation options, each with their own unique advantages and disadvantages for cost, mitigation capability, and implementation.

Gas System Expansion

The project team has examined two potential options for gas system expansion: 1) investment into gas storage, and 2) investment into gas pipeline capacity.

Gas Storage Expansion

Figure 4.2: Potential Gas Storage Expansion Mitigation Options

Case	Working capacity *(mmcf)*	Max withdrawal rate *(mmcfd)*
DSW base case	Aliso Canyon decommissioned	
Aliso Canyon operational	24,000	800
AZ Gas Storage	4,000	400

The project team ran two additional sensitivities (Figure 4.2) with additional gas storage capacity added to the DSW pipeline rupture Base Case disruption scenario:

- A scenario with Aliso Canyon remaining online at the reduced operational capacity and maximum withdrawal rates as seen at present
- A scenario with an additional Phoenix-area gas storage facility coming online, based on Kinder Morgan's proposed Arizona Gas Storage project

Figure 4.3: Unserved Energy & Unmet Reserves (GWh)

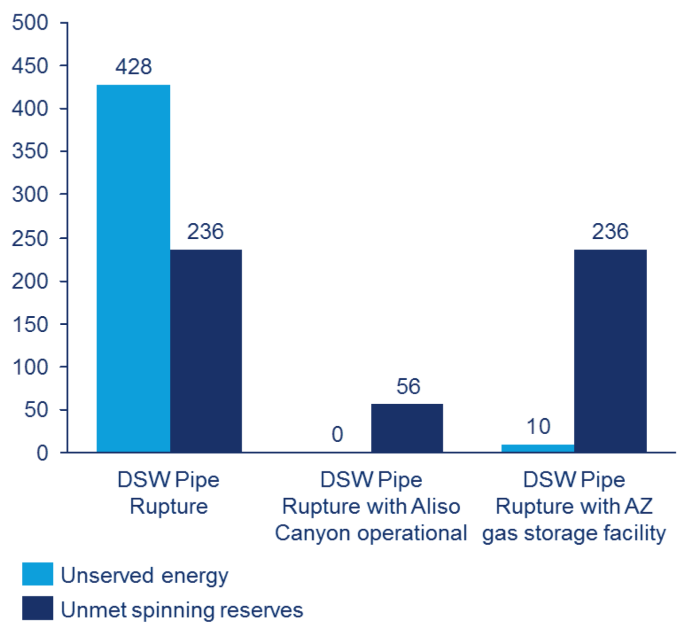
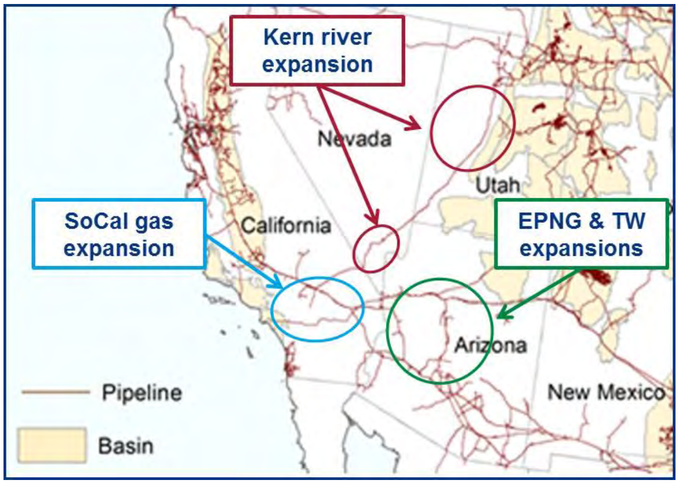


Figure 4.3 shows the resulting impacts from the additional gas storage sensitivities and illustrates the compensation capability stemming from the presence of additional market-area storage. While the problem is not completely eliminated, the presence of an additional facility in the Phoenix area greatly reduces the amount of unserved energy, and the presence of Aliso Canyon eliminates all unserved energy and significantly helps with the unmet spinning reserves. However, this compensation capability comes at the cost of requiring a larger initial investment. Resuming operation of

Aliso Canyon at present levels would incur very little incremental capital expense, but the installation of the AZ gas storage facility would cost an estimated $372 million as currently envisioned[10].

Gas Pipeline Capacity Expansion

Figure 4.4: Potential Areas for Pipeline Expansion



The other potential option involves an expansion of the gas pipeline network itself. Through flow analysis and discussions with gas pipeline operators, the project team has identified a number of possibilities for capacity expansion:

- Expansion on El Paso Natural Gas (EPNG) or Transwestern (TW) systems in Phoenix area
- Expansion on Kern River Gas Transmission (KRGT mainline
- Expansion on SoCalGas backbone system

Gas pipeline operators have indicated an incremental addition of 75 – 300 mmcfd of deliverability could be achieved with an investment of ~$25 – 500 million depending on the configuration[11], and various other expansion designs around their respective systems could add an additional 100 mmcfd – 1 bcfd of deliverability into Southern California. While pipeline system expansions would provide additional flexibility to handle long-term sustained disruptions, they face a number of challenges:

- Projects are typically evaluated on 15 – 25 year timeframes, during which California climate policy will affect the gas throughput; this makes it challenging from both an operator evaluation and open season contracting standpoint to garner support
- Interstate expansions must be approved through the FERC regulatory process, which can take 36 months or longer
- Discussions with multiple pipeline operators have all indicated a key capacity constraint around SoCalGas's system deliverability, which faces heavy political opposition to any form of expansion. If SoCalGas's ability to receive volumes from interstate pipelines and deliver into Southern California's market remains limited, any expansion upstream of those points will be ineffective

Despite these challenges, gas pipeline operators are continuously evaluating potential expansion options and pushing forward with their projects. On May 10, 2018, El Paso Natural Gas applied to FERC to authorize its South Mainline Expansion Project, which would increase capacity on the company's Line Nos. 1100 and 1103 in Hudspeth and El Paso counties in Texas. The project would expand the system with ~17 miles of a 30-inch loop line and two new compressors: a new 13,220 hp turbine-driven compressor station in Luna County, NM and a new 13,220 hp turbine-driven compressor

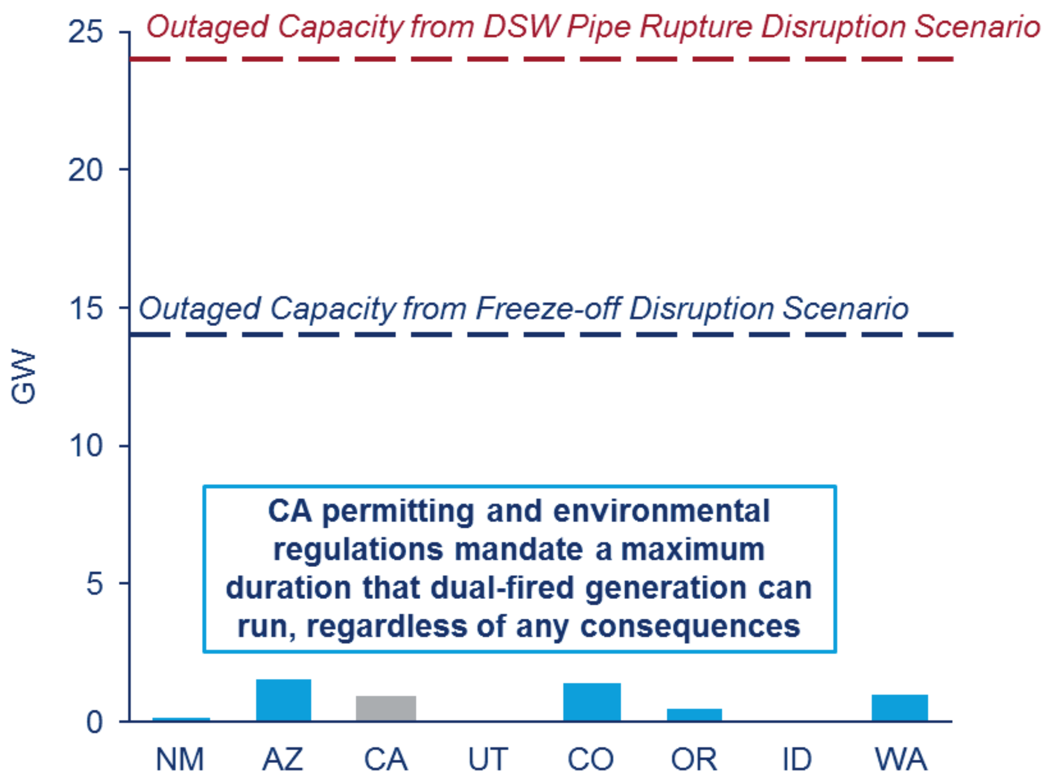
[10] As indicated by the public Open Season document (Notice ID #17005) issued by Kinder Morgan

[11] Numbers and ranges provided by key gas pipeline operators in the West

station in Cochise County, AZ. Overall capacity of the South Mainline would be expanded by ~321,000 Dth/d at an incremental cost of $127.9 million, allowing for EPNG to meet demand in the Texas, New Mexico, Arizona, and California markets. The project has two major anchor shippers: Mexico's state power company Comision Federal de Electricidad (CFE) and Salt River Project Agricultural Improvement and Power District (SRP).

Dual-Fired Generation

Figure 4.5: Estimated Available Dual-Fired Generation Capacity (DSW Pipeline Rupture Disruption Scenario)

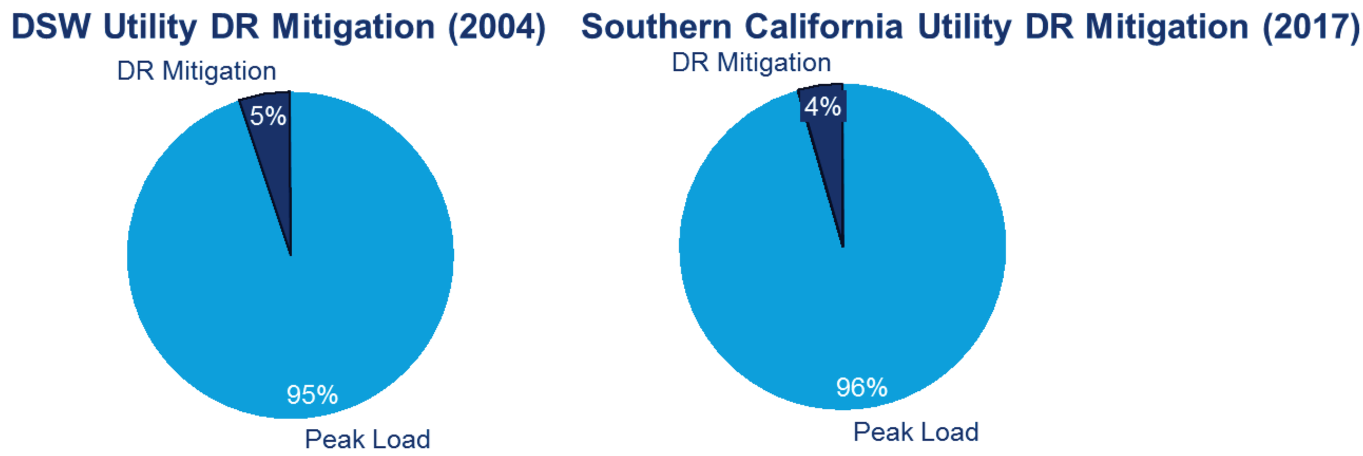


While dual-fired generation provides some additional mitigation capability, its effectiveness is limited by difficulties stemming from procurement logistics, economics, and policy opposition. Utilities typically only keep enough fuel onsite for a few days of generation (if any at all) due to associated costs of storage, at which point access product pipelines, railroads, and terminals become key. As plants attempt to procure additional fuel, truck availability and pump capacity quickly become the limiting factors. Additionally, further limitations stem from environmental and policy regulations; for example, California permitting and environmental regulations mandate a maximum duration that dual-fired generation can run for, regardless of need.

Consequently, dual-fired generation is a mitigation option that is better suited for shorter duration disruptions. In the DSW pipeline disruption scenario, we estimate that by keeping all existing dual-fired facilities online today, an additional 700 MW of compensation would be available.

Electric Demand Response (DR) Initiatives

Figure 4.6: DR Mitigation vs. Peak Load

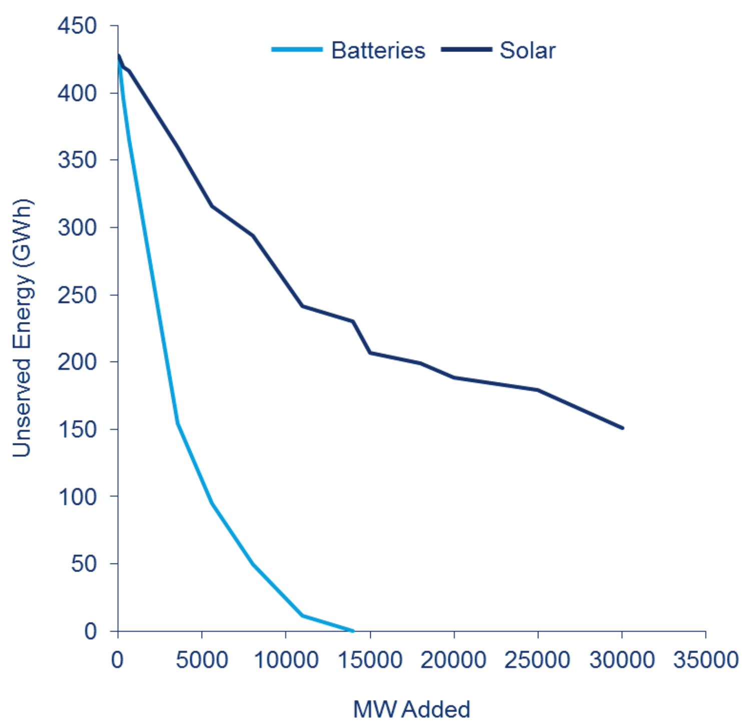


Several utilities have implemented both formal and voluntary DR programs to manage peak demand at comparatively limited costs. Looking at both historical and present-day situations, DR programs and initiatives have been able to effectively reduce peak load by ~5% of total utility load on average, indicating that DR programs are best suited for peak shaving purposes and have limited effectiveness for long-term disruptions. Moving forward, continued implementation of electric DR programs and outreach will be a key tool for managing peak demand and limiting disruption impacts.

Natural gas DR programs do not have as robust a history as electric-sector programs. This is due, in no small part, to the fact that most natural gas customers that would be good candidates for DR programs are already taking interruptible natural gas service for cost-saving reasons. Nevertheless, it is possible that additional natural gas DR programs could be brought to bear to help address the issues identified here. These programs were not considered explicitly in this analysis because of lack of data about the availability and cost of gas customer DR.

Renewables & Battery Electric Storage

Figure 4.7: Mitigation Capability of Battery & Solar Additions



As states continuously push for more aggressive renewables targets and standards, utilization and implementation will continue to grow. The potential of renewables and energy storage investments to mitigate reliability risks on the gas system depends on the specific nature of the vulnerability identified. In the case of the DSW pipeline rupture, the primary reliability risk occurs in the 4-6 hour period in the late afternoon & early evening when the sun is setting but the outages of natural gas infrastructure are insufficient to meet the upward net load ramp. As shown in Figure 4.7, the effectiveness of electric generation investments to mitigate this risk varies by technology:

- New investments in solar resources provide relatively limited reliability benefit because most of the unserved energy occurs during periods of waning solar production. In fact, adding 30,000 MW of additional solar PV resources across the Southwest and Southern California is not sufficient to eliminate the unserved energy observed in this scenario.
- Battery storage provides a more effective mitigation investment to help meet load during the sundown period, but investments of a tremendous scale are needed to eliminate the unserved energy observed in this scenario: nearly 15,000 MW of 4-hour battery storage, likely requiring capital investments on the scale of $12 to $18 billion, would be needed.

While the scale of investments needed to fully mitigate this risk using battery storage or solar alone is prohibitive, this analysis suggests that consideration of reliability benefits associated with mitigation of gas system contingencies may be useful to incorporate in utility procurement decision-making processes.

Protocols & Procedures Improvement Recommendations

Figure 4.8: Recommendations for Improvement of Gas-Electric Protocols

	Recommendations	Benefits
Improved Regional Coordination	• Conduct regional contingency planning exercises led by WECC to prepare for a number of disruption scenarios	• Maximizes compensation ability for utilities across the Western Interconnection
Resource Adequacy Assessment	• Greater transparency of firm contracting and linkage to power plants served in firm reserve reports	• Allows for more robust planning processes, especially as gas and power capacity dynamics tighten
Curtailment Priorities	• Re-visit classification of electric generation as “non-core” end-use • Designation of plants critical to grid reliability as core end-use	• Ensuring that critical power plants are not the first to be curtailed allows for additional flexibility for compensation via transmission
Forecasting & Execution	• Require intra-day LDC core load balancing to ensure fair implementation of OFOs and penalties • Additional clarity around interstate pipeline curtailment protocol	• Higher accountability for prior-day forecasting allows easier utility operation • Explicit interstate curtailment protocols allow for better contingency planning
Gas-Electric Day Mismatch	• Split weekend nomination period into daily blocks, resulting in a 7-day nomination cycle	• A feasible step for both gas and electric sides that would minimize response lead times over the weekend period

The disruption scenario modeling described above assumes "perfect" response from electric generators in the Western Interconnection; that is, any electric generator that is not also disrupted by the assumed gas delivery challenge is assumed to respond instantaneously to prevent loss of load in the Western Interconnection, even if the load is located several states away. In order to approach perfect commitment and dispatch, and a perfect procurement level of compensation as seen in our modeling efforts, it is imperative that gas and electric industry protocols are properly aligned and coordinated. To this end, the project team has identified a number of actionable recommendations and improvements to existing processes:

1. **Improved Regional Coordination:** We recommend that WECC lead and conduct regional contingency planning exercises to prepare for a number of disruption scenarios. In a real-world event, achieving perfect dispatch and procurement is highly difficult; additionally, compensation for impacted plants often comes from different regions due to the interconnected nature of both the gas transmission pipelines and electric transmission lines. Consequently, regional coordination stemming from pre-emptive contingency planning allows for faster reaction and greater compensation capability.
2. **Resource Adequacy Assessment:** We recommend greater transparency and clarity around procurement and supply of gas to gas-fired power plants. Having an accurate view of how much capacity and which power plants are covered by firm transport (FT) contracts as well as deals with third-party suppliers allows for better firm reserves analysis and more robust contingency planning processes. As shown above in Section 3, a significant amount of plant generation relies on interruptible transport (IT) for their gas. While this arrangement functioned adequately in the past, as gas dynamics tighten it will become increasingly important to understand how specific plants are sourced in order to fully understand which plants are at risk during a sustained disruption. Having this information explicitly provided allows for more robust contingency planning exercises, which are not currently conducted on a consistent basis at the utility/generator level.
3. **Curtailment Protocols:** We believe that there is support from both the gas and electric industries to re-visit the classification of electric generation as non-core end-use in California. Under the current protocol, power generation is often the first class of customers to be curtailed; while the difficulty of restoring residential service makes it unlikely that the entire generation customer base would be re-classified, we believe that it would be feasible to designate specific plants as critical to grid reliability and move them into the core classification, which would aid during curtailment situations.
4. **Forecasting & Execution:** We have identified a number of changes to existing protocols that could improve forecasting and execution. Currently, regulations in California only require LDCs to balance core loads against previous-day nominations for that particular day. Consequently, when the difference between the forecasted and actual demand becomes apparent, LDCs issue OFOs and lean upon the utilities and generators to adjust for any discrepancies; this makes it difficult for the utilities and generators to operate from day-to-day. The other area that we recommend adjustments regards clarity around interstate pipeline curtailment protocols. While curtailments are typically done on a pro-rata basis in the order of IT, secondary FT, and FT contracts, there are typically various exceptions to this based upon the configuration of the pipeline, as operators typically try to be flexible and avoid curtailing supply to customers who have no other possible gas source. Having these practices made explicit would allow for better and more accurate contingency planning.
5. **Gas-Electric Nomination Days:** The gas-electric nomination day mismatch continues to be a challenge for coordination between the two industries. While we view it unlikely for the two nomination schedules to become fully aligned, we suggest that the weekend nomination period be split into daily blocks, resulting in a 7-day nomination cycle. We view this as an action that would help minimize response lead times over the weekend period and as something that would be feasible to accomplish from a regulatory standpoint.

Conclusions

The results of this study highlight the potential risks to the gas-electric system in the Western Interconnection as forecasted retirements and higher renewable generation pose a key challenge to reliability. Both the modeling scenarios and recent real-world events point towards a system being pushed to its limit, indicating that the Western Interconnection is at an important crossroads in its trajectory:

- Recent events stemming from unexpected pipeline outages and gas supply freeze-offs are indicative of a gas-electric system already under considerable stress, which has been significantly exacerbated by restrictions on the operation of Aliso Canyon
- Despite expected increases in renewable generation, regional gas burn is expected to increase over the forecast period driven by baseload coal and nuclear retirements as well as steady load growth
- The configuration of the gas-electric system combined with the potential closure of Aliso Canyon creates region-wide reliability issues centered around the markets concentrated in Southern California and Phoenix; disruption scenarios revolving around a DSW pipeline rupture or Permian/San Juan Basin supply freeze-offs routinely result in unserved energy and/or unmet spinning reserves.

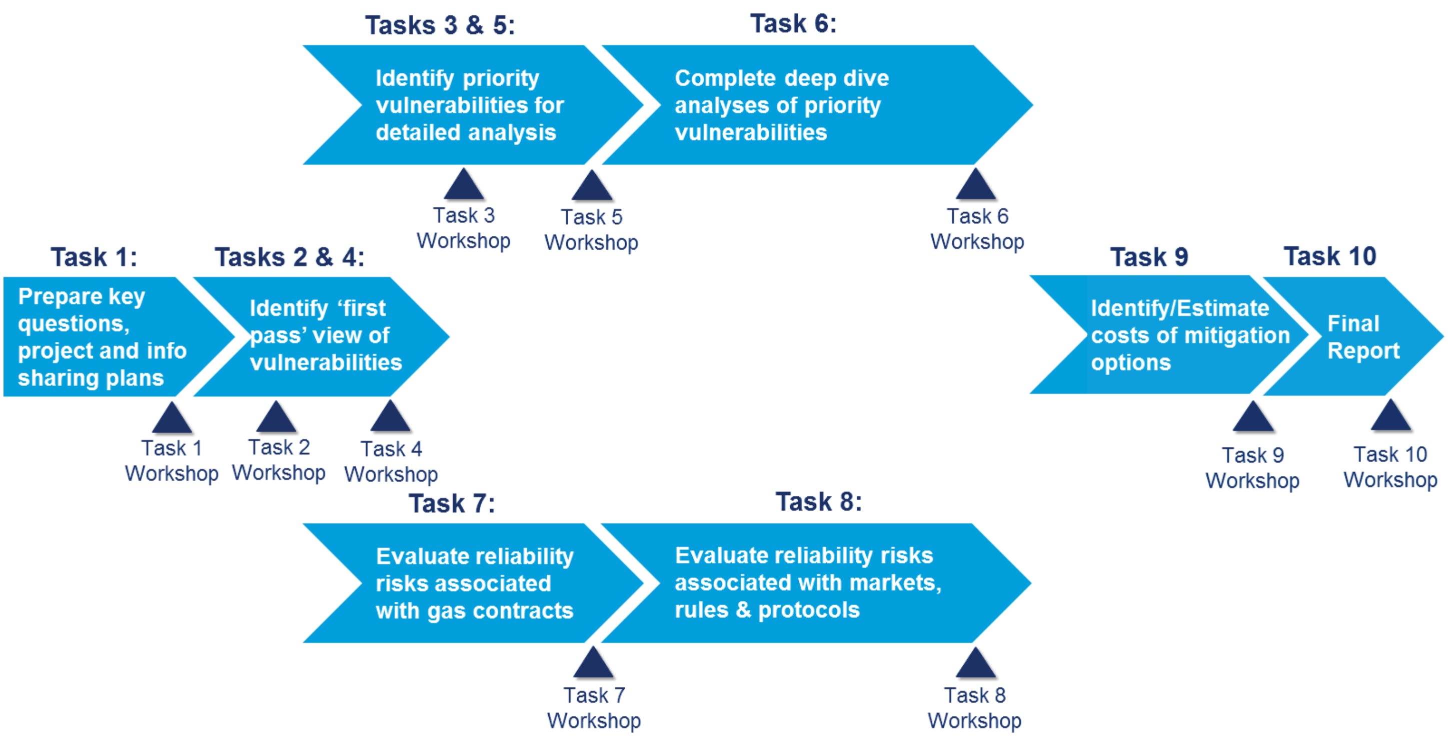
- Other regions in the Western Interconnection are more resilient to major gas system disruptions, largely owing to increased compensation capabilities stemming from availability of market-area gas storage and alternative sources of energy including reliance on the region's robust interstate transmission system
- The existing strain on the system indicates that even modest changes to working assumptions such as fossil fuel plant closures or natural gas storage limits could rapidly exacerbate existing challenges; natural gas support will continue to be necessary to ensure system reliability while achieving policy goals.

Consequently, the development of a balanced portfolio of mitigation options is critical to assure system reliability in a changing power landscape. Maintenance and new investments in gas and electric infrastructure are necessary to meet both near-term needs and bulk power system capacity needs:

- If Aliso Canyon is closed, a combination of mitigation options would be needed to ensure system security and reliability: investment in gas infrastructure and storage, renewable generation, battery storage, demand response programs, and dual-fuel generation.
- Should Aliso Canyon stay online in its current, limited capacity, disruptions of the natural gas system would have a more limited impact but would likely not be completely eliminated, underlining the importance of the implementation of a portfolio of the mitigation options previously mentioned
- Improved coordination of gas and electric industries' operating practices will be critical for maximizing compensation capability and ability to respond to both business-as-usual and sustained disruption scenarios
- Moving these changes forward will require buy-in at all levels (e.g. gas pipeline operators, utilities, generators, PUCs, NERC, NAESB, FERC) in order to effectively improve existing protocols and procedures

Appendix A: Project Structure & Work Streams

Figure 1: Project Plan & Structure



The study was split into 10 discrete tasks in order to allow for a flexible approach to home in and focus upon the key aspects and vulnerabilities as they became apparent during our study, with numerous workshops to ensure engagement of the stakeholder advisory teams. These 10 tasks can be categorized into four separate but highly interconnected work streams:

- **Project Setup & Preparation (Task 1)**: In order to ensure project alignment and focus on the most important concerns relevant to the key stakeholders, the project team established a team structure and avenues of communication early on to facilitate information flow and make sure all feedback was captured
- **Vulnerability Analysis & Scenario Runs (Tasks 2, 3, 4, 5, 6)**: The project team modified and reconciled the three internal models of AURORA, GPCM®, and NGfast to reflect the 2026 WECC Common Case, which served as the basis for the analysis conducted in the study. A first pass view of vulnerabilities was formulated and subsequently refined using work from previous studies as well as input from gas and electric stakeholders. A subset of 10 scenarios for modeling analysis was agreed on, upon which the project team tested and improved the modeling approach first in the Desert Southwest ("DSW") before extending to the rest of the Western Interconnection. After thorough validation of the approach and the results, the project team was able to calculate the unserved energy and unmet spinning reserves resulting from each disruption scenario. This impact was then translated into an associated economic impact
- **Gas Contracting Analysis & Existing Protocols Risk Identification (Tasks 7, 8)**: In parallel, the project team conducted an analysis of existing gas contracting positions held by all utilities and generators in the Western Interconnection to provide a view on the region's reliance on interruptible transport ("IT") contracts. Additionally, this exercise allowed for the refinement of existing contracting datasets critical for improving the accuracy of our modeling scenarios in the above work stream. Contracting data was validated through interviews and discussions with the regional gas and electric stakeholders, who also provided insights and views towards friction areas and pressure points within existing processes and protocols that hindered their daily operations
- **Mitigation Options Analysis & Recommendations (Task 9, 10)**: After identifying the key vulnerabilities and quantifying their impacts, the project team analyzed cost and capability for multiple options to assess situations for which each would be most applicable. Additionally, the team provided actionable recommendations for existing

processes and protocols for facilitating coordination in order to aid contingency planning and responses as well as improve daily operations

Appendix B: Glossary

Associated Gas: A form of natural gas which is found with deposits of petroleum, either dissolved in the oil or as a free gas cap above the oil in the reservoir.

Basin: Basin region. Includes Nevada and Utah.

Bcf: Billion cubic feet.

Bcfd: Billion cubic feet per day.

BPS: Bulk Power System.

CPUC: California Public Utility Commission. Regulates services and utilities, protects customers, safeguards the environment, and assures Californians' access to safe and reliable utility infrastructure and services. Essential services regulated include electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies.

Demand Response (DR) Program: Programs being used by some electric system planners and operators as resource options for balancing supply and demand by providing opportunities and incentives for consumers to reduce or shift electricity usage during peak periods.

DOT: Department of Transportation.

DSW: Desert Southwest region. Includes New Mexico, Arizona, and Texas.

EPNG: El Paso Natural Gas pipeline. Owned by Kinder Morgan and transports natural gas from the San Juan, Permian, and Anadarko basins to California, Arizona, Nevada, New Mexico, Oklahoma, Texas, and northern Mexico.

FERC: Federal Energy Regulatory Commission. Independent agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects

Freeze-off: Phenomenon where below freezing temperatures cause production shutoff when wellhead gas flow is blocked by formation of ice.

FT: Firm Transportation. FT contracts ensure pipeline capacity on a firm basis and are generally not subject to reduction or interruption.

GTN: Gas Transmission Northwest. Gas pipeline that transports WCSB and Rockies gas to Washington, Oregon, and California.

IT: Interruptible Transportation. IT contracts are subject to curtailment or interruption due to operating conditions or pipeline capacity constraints.

KRGT: Kern River Gas Transmission. Gas pipeline that transports gas from southwestern Wyoming, through Utah and Nevada, to the San Joaquin Valley near Bakersfield, California.

Line Pack: A procedure for allowing more gas to enter a pipeline than is being withdrawn, thus increasing the pressure and effectively creating storage.

LDC: Local Distribution Company. Regulated utilities involved in the delivery of natural gas to customers within a specific geographic area.

Mmbtu: Million British thermal units.

Mmcfd: Million cubic feet per day.

N-1: Refers to a contingency involving the unexpected failure or outage of a system component.

N-2: Refers to a contingency involving two unexpected failures or outages of system components.

NAESB: North American Energy Standards Board.

NERC: North American Electric Reliability Corporation. Non-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

OFO: Operational Flow Order.

PHMSA: Pipeline and Hazardous Materials Safety Administration

PNW: Pacific Northwest region. Includes Washington, Oregon, and Idaho.

PV: Photovoltaic.

Rockies: Rockies region. Includes Colorado, Montana, South Dakota, and Wyoming.

RPS: Renewable Portfolio Standard. Regulation that requires the increased production of energy from renewable energy sources.

SoCalGas: Subsidiary of Sempra Energy responsible for distributing and servicing natural gas to Central and Southern California.

Spinning Reserves: On-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 minutes of a dispatch instruction. Needed to maintain system frequency stability during emergency operating conditions and unforeseen load swings.

TW: Transwestern pipeline. Owned by Energy Transfer and transports natural gas from the San Juan, Permian, and Anadarko basins to California, Arizona, Nevada, and New Mexico.

WCSB: Western Canadian Sedimentary Basin. A key oil and gas producing basin in Western Canada.

WECC: Western Electricity Coordinating Council. Non-profit corporation that exists to assure a reliable BPS in the Western Interconnection. Approved by FERC as the regional entity for the Western Interconnection, and possesses authority from NERC to create, monitor, and enforce reliability standards.

WECC 2026 Common Case: Forecast produced by WECC that represents the expected loads, resources and transmission topology 10 years in the future from a given reference year. For this study, v1.5 was used as the basis for analysis.

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